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ELECTRIC POWER WHEELING AND DEALING

Technological Considerations for Increasing Competition

CONGRESS OF THE UNITED STATES OFFICE OF TECHNOLOGY ASSESSMENT

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Technological Considerations for Increasing Competition

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Foreword

This assessment responds to a request by the House Committee on Energy and Commerce for OTA to evaluate the technical feasibility of increased competition in the electric utility industry. In particular, the Committee requested an analysis of the impact of increased wheeling on the reliability and operation of the transmission systems. Wheeling is the use of a utility's transmission facilities to transmit power for other buyers and sellers.

Competition is being introduced into the electric utility industry in an effort to control costs, encourage innovation, and create business opportunities. Competition among providers of new generating capacity is increasing rapidly, and many purchasers of power are seeking access to these suppliers through wheeling. However, doubts remain as to whether the operation of the electric system will be as economic and reliable under competition as it has been under the present industry structure and regulatory framework.

This assessment analyzes how the Nation's power systems could accommodate various proposals for competition intended to make the electric power industry more responsive to market forces. Operation of an electric power system is extremely complex, and increased competition could have serious effects on costs and reliability if not implemented carefully. The assessment identifies the technical requirements that must be met to keep the system working well as the level of competition increases, and determines how competitive enterprises could meet these requirements.

OTA is grateful for the substantial help received from many organizations and individuals in the course of this study. The project's advisory panel and workshop participants provided invaluable guidance. Reviewers of the draft report contributed greatly to its accuracy and objectivity. Contractors prepared reports (which will be made available in Volume II of this report) that were essential in evaluating the often speculative claims of the advantages and disadvantages of competition.

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Overview

Competition has been proposed as a mechanism to reduce costs and improve decisionmaking in the heavily regulated electric power industry. Some elements of competition are already appearing. However, the technical characteristics of electric power systems, and deficiencies in data and analysis of the requirements for planning and operation under competition, result in uncertainty over the costs and benefits. In particular, changes affecting the transmission system could cause major reliability and cost problems unless introduced carefully.

Concerns that the bulk power system (generation and transmission) is inherently incompatible with competition do not appear to be well founded. The system can be made to work under any of the institutional/regulatory arrangements considered in this study. Problems and issues will arise with widespread competition, but they will be much less technical than political and institutional.

The greatest challenge will be to maintain the coordination of the bulk power system as an integrated whole when many different entities are involved. At present, utilities (or groups of cooperating utilities) control the output of all their generating plants to ensure reliability and lowest possible cost for the constantly changing demand, considering the availability of transmission capacity. If competition is to be successful, it must find a way to provide the same services that utilities now perform internally. The solution will depend more on measures to define responsibilities and ensure adequate information sharing than on hardware modifications.

Competition is not a single concept. The term encompasses a variety of proposed changes. The major potential mechanisms are increasing competition among generating companies for the sale of their power, and expanding access to the transmission system so that this power can be wheeled to different customers. The various proposals differ largely in the rapidity of introduction and eventual extent of change in these two themes.

The costs, benefits, and impacts of competition are very uncertain. Actual experience is limited, and little analysis has been performed. The benefits from competition are speculative and difficult to quantify, particularly from a national perspective. Rapid change will entail the greatest risks, and special attention will have to be paid to developing appropriate institutional safeguards. Key data, such as the amount of wheeling going on now and the amount of nonutility generation, is not being collected in useful form.

If implemented unwisely, competition easily could result in higher costs and lower reliability because crucial functions such as economic dispatch would not work as effectively. Success is likely to depend on how competition is implemented, both for the Nation as a whole and for individual transactions.

Some elements of competition are already being implemented. Several States are initiating bidding procedures to allow nonutility companies to compete to supply new generating needs at the lowest possible cost. Bulk power sales between utilities have been substantial for many years. Interest in such sales among utilities, independent generators, and consumers is increasing.

The environmental impacts of competitive generation will depend on how it is implemented. Competitive generators might select different fuels and technologies than would utilities, which would result in different environmental impacts, but this cannot be predicted confidently. In addition, there has been increasing concern over the health impacts of the electric and magnetic fields associated with transmission lines. These impacts cannot be confirmed at this time, but neither have they been disproved.

If policymakers choose to encourage competition, modifications to the Federal Power Act, the Public Utility Regulatory Policies Act and the Public Utilities Holding Company Act could remove disincentives to bulk power competition and increased wheeling. In addition, several technical and institutional changes could help ensure that the electric power system operates reliably and economically. Many services that utilities now provide internally will have to be arranged by contract, which will require precise definition and evaluation. Detailed data collection and analysis could identify risks to be avoided as competition is implemented. State and Federal regulatory bodies may require increased expertise to handle complex issues.

Chapter 1

Introduction and Summary

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Chapter 1

Introduction and Summary

INTRODUCTION

The electric utility industry is facing unprecedented changes. Problems of the past and uncertainties in the future are prompting an examination of alternative ways to manage the Nation's electric power systems. A major focus of this search is competition—revising the regulation that has controlled most aspects of electric utilities to make better use of market forces. However, competition itself raises a host of questions: how can it best be applied to the electric utility industry? what has to be done to make the electric system work under these arrangements? how would reliability and costs compare to the present system? can the transmission network handle increased transfers of bulk power? This assessment explores the technical requirements for introducing greater competition into the operation and planning of the electric power industry, with particular emphasis on reliability and operation of the transmission network.

Competition is not a single concept. It can be applied in different ways that have quite different implications. This assessment considers two major mechanisms: competition among generators to supply electric power; and expanding access to the transmission network for wheeling of bulk power from seller to buyer. Competitive generation can be introduced without providing access to transmission, but it is likely that any significant move toward competition would include some degree of both.

Background

For nearly a century, regulated utilities have provided most electric power in the United States. These utilities generate or buy the power needed in their assigned service areas and deliver it to their customers via long-distance transmission and local distribution networks. They also plan for future growth and build needed facilities. Regulators review costs and set the rates utilities charge customers. Until the early seventies, this system appeared to work well: the supply of electricity was reliable, and each new plant contributed to lower costs.

The energy crisis of 1973 and subsequent economic problems brought rapid and painful change to the electric utility industry. Fuel prices and construction costs of new power plants, particularly nuclear, rose dramatically during this period due to a combination of factors—the OPEC oil embargo, increased environmental and safety requirements, high interest rates, intentional construction stretchouts due to lack of need, and poor management in some cases.

Higher fuel and capital costs meant higher electricity costs, and utilities sought substantial rate increases. Customers responded by using less electricity, a reaction that most utilities underestimated at first. In addition, some consumer uses, such as major residential appliances, started approaching saturation. Many large industrial users of electricity, such as aluminum and bulk chemicals, experienced declines in domestic production due to foreign competition. In addition, some manufacturing companies and other large electricity users found they could save money by generating their own power, usually in conjunction with the production of process steam (cogeneration), further depressing demand for utility power. Growth rates of overall national demand plummeted from 7 percent per year to less than 2.5 percent by 1980 (with considerable regional variation). Reductions in construction programs lagged the drop in demand, and many utilities developed considerable excess capacity.

As utility costs of production increased, State regulatory commissions scrutinized utility expenditures much more closely, especially the huge construction cost escalations for nuclear plants.

In some cases, regulators determined that plants were unnecessarily expensive or that the generating capacity was not needed and did not allow the utility to charge customers for the entire cost.

Perhaps the most critical legacy of the 1970s is *uncertainty* in electricity demand growth. After 1972, not only did the average annual demand growth rate drop to less than a third of that of the previous decade, but the year-to-year changes became less predictable as well. Users of electricity often are able to switch rapidly to other energy forms or improve the efficiency of their use. However, rapid demand growth continues in some sectors, such as space conditioning for commercial buildings, industrial process heat, and electronic office equipment. As growth has become less predictable, utility planning has become more complex.

The last 15 years have been difficult for many utilities, several having come close to bankruptcy, and have greatly raised costs for their customers. Since about 1983, however, most problems seemed to have waned. The cost of producing electricity has leveled out (and even declined in some areas) as fuel prices dropped and costly construction programs were phased out. Demand has risen, and surplus capacity has been utilized.

Despite a substantial return toward financial health, some problems have left permanent changes. The trend toward large, capital-intensive power plants seems to have ended, at least for the time being, for a variety of reasons including uncertainty over future demand and concern over potential cost disallowances by State regulatory commissions.

The Public Utility Regulatory Policies Act of 1978 (PURPA) has also had a major industry impact. Among other things, PURPA was intended to encourage construction of nonutility, generating units by requiring utilities to purchase power produced by qualified facilities (QFs).[1] Despite a slow start due to economic uncertainties and legal challenges, the number of QFs has grown rapidly. Many cogeneration and alternative energy facilities appearing since 1978 have been a result of PURPA. The Act has also inspired a growing interest in independently owned, but otherwise conventional power stations, which would sell their output to utilities or even directly to other customers, perhaps using a utility's transmission system for the delivery.

Several States have already initiated procedures to further promote nonutility generation, sometimes with the active encouragement of their utilities. Utilities in need of new generating capacity can request proposals in a competitive bidding process and then contract with other utilities, cogenerators, or independent power producers (IPPs). In 1988 the Federal Energy Regulatory Commission (FERC) proposed changes to regulations to promote competition in bidding and independent power production.[2]

Cost differentials between utilities are also fostering change. Some utilities are able to sell excess power at low prices. Other utilities have taken advantage of such opportunities for many years. Large industrial consumers and municipal electric distribution agencies in high cost areas also are seeking to purchase lower cost electricity directly from distant utilities. Such efforts often conflict with interests of the local utility, which doesn't want to lose customers and may refuse to supply transmission services, or wheeling, for power produced by other parties.

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[1] PURPA encourages alternative energy and high efficiency cogeneration through special regulatory treatment. Power from QFs must be purchased by the local utility at a price not to exceed the cost that the utility would have incurred to generate the same power. These limits have been set administratively by State utility commissions, and there has been considerable controversy over whether avoided costs have been set at levels too high, encouraging too many QFs at consumer expense, or too low, discouraging innovative development. FERC has proposed a rule approving the use of competitive bidding as a means of determining avoided costs under State regulatory programs.

[2] Notices of Proposed Rulemaking: Docket No. RM88-4, Regulations Governing Independent Power Producers; Docket No. RM88-5, Regulations Governing Bidding Programs; Docket No. RM88-6, Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities; Mar. 16, 1988.

Change is also occurring in other countries. In particular, the British Government is introducing competition into its generation and transmission system through a radical privatization of its presently government-owned monopoly. This situation is quite different, but it may well provide some useful lessons for the United States.

Future Concerns

All these factors suggest that change is inevitable for the electric utility industry. However, there are many different views on what the appropriate changes should be. To a large extent, partisans of each perspective in the debate are motivated by self-interest. The stakes are large for many of the players. From the perspective of those trying to maximize benefits for the Nation as a whole, the issues are more ambiguous.

The primary argument advanced for policymakers to take some action, whether involving competition or another approach, is that the present institutional and regulatory structure seems unlikely to produce the lowest possible costs for consumers. Some people believe that the problems are too systemic to be addressed by adjustments in the existing regulatory approach: that utilities lack sufficient incentive or ability to control construction costs and operate as economically as possible. Prior to the disallowances of recent years, costs and savings generally were simply passed on to customers, with little reward to the utility for excellent performance or penalty for inefficiency. According to these arguments, competition could help ensure that the lowest cost facilities are built and operated efficiently, and that customers would always have access to the lowest cost power available, no matter who generated it.

Others believe that the problems of the past were one-time events, not likely to be repeated, and that the present regulatory structure can be adjusted to handle any future problems. In fact, some holders of this perspective believe that no competition should be introduced; that unique characteristics of the electric system mean that competition is likely to raise costs and lower reliability.

One of the key elements of the debate is over new construction to meet future needs. Some observers are concerned that under the present regulatory environment utilities will jeopardize future reliability and cost control by failing to construct needed facilities or building only plants with the lowest possible capital cost, such as oil- or gas-fired turbines, which often have high operating costs. Others are concerned that capital minimization is exactly the choice that most competitive generators would select. If new generating plants rely primarily on gas- or oil-fired turbines, and if the prices of those fuels rise sharply as they have several times in the past, electricity could become significantly more expensive. Under some conditions, large coal or nuclear plants could still produce the lowest cost power.[3] Policymakers may wish to consider revisions to regulations so that utilities can confidently build whatever facilities are deemed least expensive overall for their customers, or encourage competitive entities to build these facilities. However, the choice of fuels for future generating stations and their national energy and environmental policy ramifications are beyond the scope of this study.

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[3] Nuclear and coal plants have low fuel costs compared to gas- and oil-fired plants. If their capital costs are not too high, the fuel cost advantage can result in lower overall cost per kilowatthour. At the moment, this is probably generally not the case. Oil and gas prices are not much higher than coal though gas prices are climbing. Future competitiveness for nuclear and coal will depend on holding capital costs down as well as renewed increases in oil and gas prices. Despite the spectacular capital cost increases in the seventies, this appears possible. Some of the factors driving those increases were peculiar to the times (20 percent interest rates and construction delays due to plummeting demand). Others were one-time increases that would not continue pushing prices up (strengthening inadequate safety and environmental controls). Thus it should not be assumed that the experience of the past is necessarily indicative of the future.

Another concern is that increased competition will be hindered by existing laws and regulations. Pressure for more competition is increasing and some elements are already being introduced. If Congress chooses to encourage competition, legislation and oversight of regulation is likely to be necessary to allow full implementation.

It is also of concern that change could occur too rapidly. If competition is implemented with little testing and analysis, the economics and reliability of the system could be threatened. Therefore, policymakers may have to guide the process of change to ensure that it follows constructive channels.

A MORE COMPETITIVE ELECTRIC POWER INDUSTRY

Interutility sales have long comprised a form of competition in generation as utilities with excess capacity competed to sell power to those that needed additional power. Typically these interutility transactions benefited all parties and encouraged efficient operation.

Measures to increase competition can range from minor changes in regulatory standards and bulk power procurement practices to a major reorganization of the industry: separating generation, transmission, and distribution into separate companies. The efforts by several States to expand market opportunities for utilities to procure new supplies of power is one form of competitive generation.[4]

Expanded access to the transmission system would increase competition by permitting (when possible) generating companies to deliver power to customers other than the local utility. The widened market increases opportunities available to independents and also to utilities with excess power to sell.

Competitive generation and transmission access can be combined. In the extreme, generating companies or any entrepreneur could build a power plant and sell output to any retail or wholesale customer at a mutually agreed on price, much as the natural gas industry operates. Purchases by a regulated distribution company might still be subject to regulatory review, but generating company costs and operations would be increasingly subject to market discipline. Under such conditions, transmission companies could even act as common carriers, available to any party wishing to arrange delivery of bulk power.

Increased competition, of whatever form and degree, is likely to have significant implications for consumers as well as for existing utilities and new entities in the industry. The following sections summarize arguments for and against competition as it might affect consumers of electric power. Major uncertainties behind these arguments are also identified.

Suggested Advantages to Competition

Some proponents of increased competition in the electric utility industry suggest that it will ensure the lowest possible costs for customers. They believe it would provide incentives for utilities and other generators to improve the operating efficiency of existing plants and control capital costs of future plants. Large differences in construction and operating costs of similar plants indicate that considerable savings are possible if competition can motivate or replace the more poorly performing utilities.

Expanding the ranks of generating companies could reveal attractive opportunities not available to utilities. Entrepreneurial generators might also be able to use lower cost financing techniques (e.g., greater use of debt relative to equity than is normal utility practice). Competitive generators could prove more innovative because, unlike utilities, they get to keep the reward if a gamble pays off.

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[4] California, Colorado, Connecticut, Maine, Massachusetts, and New York have formally adopted utility bidding programs for new power supplies. Another 17 States are implementing or considering such a step. Virginia has implemented bidding without a formal program.

Some risk would also be shifted from utilities and their rate payers to competitive generators. For instance, if costs did get out of control on a construction project, the cost of power could still be fixed by contract terms.

Transmission access might also reduce regional cost differentials by increasing bulk purchases by higher cost utilities from lower cost suppliers with excess capacity. Bulk power sales over long distances may forestall expensive new construction in regions that are growing rapidly while providing economic benefits in regions that have considerable excess capacity.

Proponents also point to precedents in the deregulation of other industries, such as natural gas pipelines, airlines, trucking, and telecommunications.

Suggested Disadvantages to Competition

In some ways, the present system works well. Utilities determine the need for power, the most economical choice to produce and deliver it, and how to ensure its reliability. This integrated approach enables utilities to optimize the entire system. Even if competitive generators can operate more economically than utilities, long-term system economics also depend on how well individual components work together. Not only are many individual utilities vertically integrated, but close coordination among utilities enables them to share generation and transmission to minimize costs and improve reliability. While some utility performance has been less than ideal, **separating a system's mutually dependent areas of decisionmaking may introduce a different kind of inefficiency that could be costlier than that intended to be addressed by competition**.

Opponents also note that many problems (such as overbuilding and construction cost overruns) that have led to interest in competition can be (or already have been) addressed within the present institutional/regulatory structure. The threat of disallowances for imprudent investments is a powerful incentive to control costs, and there is no inherent reason why utilities could not use the same financing techniques as nonutility generators. In addition, risks to consumers are not necessarily lessened when utilities buy instead of build, because the utilities will have to sign long-term contracts for purchased power. If the utility guesses wrong on its power needs, a contract could, depending on its terms, prove as inflexible as a construction program.

The present industry also supports research and development, for example, at the Electric Power Research Institute. Further, utilities often collaborate in demonstrating new technology and share information on improvements. Competing companies have less incentive to cooperate to this degree, and it is questionable how much joint R&D will continue. Similarly, utilities have fostered emerging technologies that they believed to be in the national interest but that entailed considerable initial economic risk. Competitive generators may be less likely to take such a long-term perspective.

Uncertainties

One notable feature of the debate over competition is the lack of data and analysis. Experience with competition in the electric power industry has been limited, and much has not been relevant to a situation where competitively procured supplies represent more than a small part of the whole. **For the most part, the advantages and disadvantages discussed above are speculative**.

We do not know how much more efficiently, if at all, nonutility generators can build and operate power plants. Nor do we know how much more difficult it will be to plan and operate a bulk power system that incorporates increasing competition among generators and expands access to the transmission system. **Thus we**

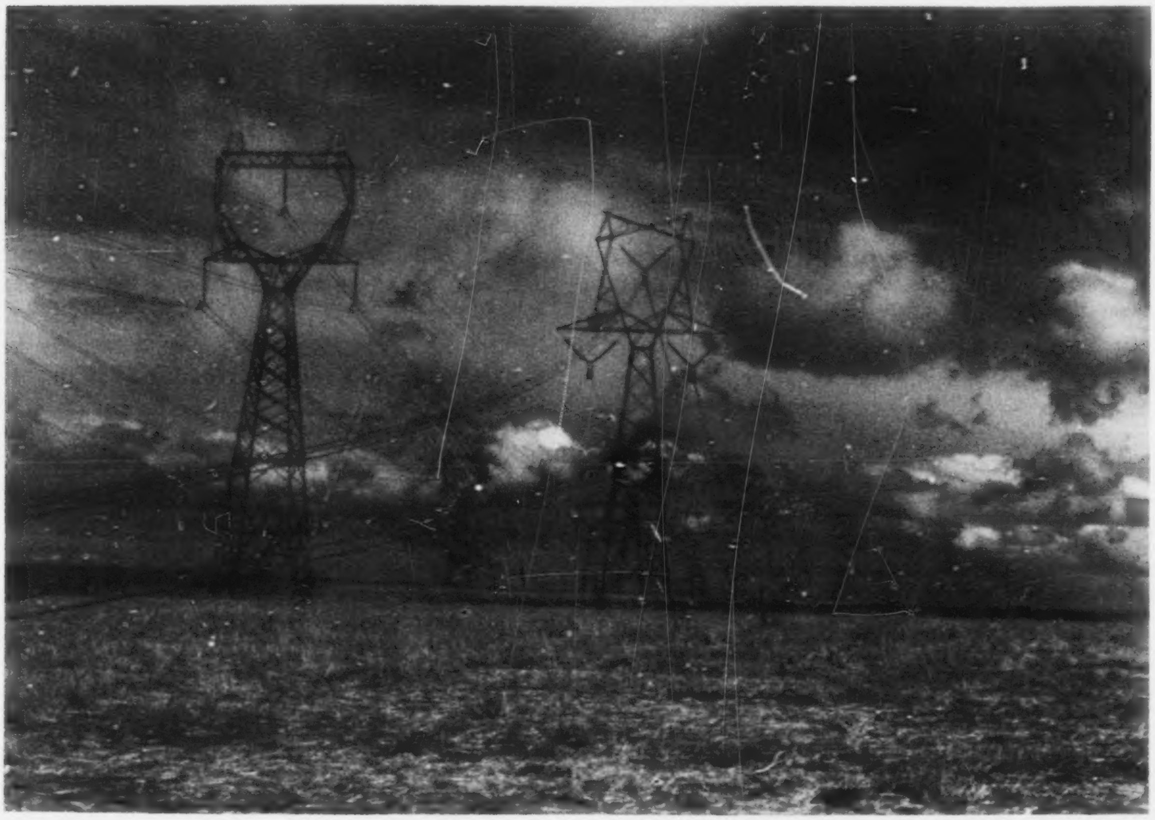

Photo credit: Casazza, Schultz & Associates, Inc.

Three extra high voltage lines share a single right of way

cannot say whether economic gains induced by competition outweigh additional costs.

Maintaining reliability under competition also poses uncertainty. Most of us take the reliability of electric power for granted, but it doesn't happen by accident. It has required investments in equipment and manpower and emergency assistance to other utilities that at times have gone beyond legal requirements. Utilities have a deeply engrained ethos that interruption of service should be minimized. The operating availability of nonutility generators to date is at least comparable to that of utilities (the owners have incentive to stay on line because otherwise they don't get paid), and appropriate reliability requirements can be built into contracts. However, system reliability is as yet untested for a situation where a large proportion of components are operated under contract rather than under direct ownership of a utility committed to meeting demand under all conditions.

Increased access to transmission should facilitate transfers of bulk power, but the growth that would result is uncertain. Bulk transfers have increased as utilities took advantage of the availability of lower cost power. More such transfers might be advantageous, but more analysis is required of where these transfers would take place, what factors are hindering them, or what their value would be.

Pricing and equity questions will be crucial to successful implementation of competition. Pricing policies will guide the operating and planning decisions made by buyers, sellers, and transporters, which will determine whether increased access to the transmission system actually allows a more efficient pattern of bulk power transfers. Contentious equity issues will emerge if some groups seem to benefit at the expense of others. For instance, large industrial customers could bargain for low rates, leaving those who lack that option (e.g., residential users) with much higher costs. In addition, if utilities are broken up into generating, transmission, and distribution companies, the transfer of the value of existing assets (which may be worth much more than their depreciated book value) will be controversial.[5]

As already noted, future fuel choices have vital national energy implications, but it is not clear what technologies or fuels either utilities or nonutility generators are likely to prefer, in part because long-term economics are not clear. National energy choices may require fuel shifts, for instance to avoid gas and oil shortages or reduce emissions of carbon dioxide because of the greenhouse effect. If responsibility for generation has diffused among a large number of independent power producers, the effectiveness of policy changes will be less predictable.

Another question is on end-use efficiency improvements. Many institutional barriers hinder otherwise economic investments to improve efficiency of end-use. For example, consumers often lack information on the availability and advantages of high-efficiency appliances. At present, utilities have some incentive to help their customers with these investments in order to avoid building expensive, new generating facilities. The impact on efficiency of use depends largely on how competition is implemented. Increased competition may improve price signals, which would improve consumer decisions, and bidding programs can include demand-side management investments. However, competition could also eliminate utility interest in overcoming noneconomic barriers to efficiency gains. A strong emphasis on increasing the efficiency of electricity use could reduce the need for new construction. A full analysis of the costs and benefits of a Federal program focused on efficiency gains as a means of optimizing the value of electricity to society was beyond the scope of this project. However, the report notes the impact on demand management of policy initiatives for implementing competition.

This assessment has not identified any specific reason why competition cannot be made to work well, but insufficient analysis has been done to determine whether benefits outweigh costs overall. It is clear that there are ways of implementing competition that would work very poorly. There are many pitfalls that must be avoided.

THE BULK POWER SYSTEM

The production and delivery of electric power is extremely complex, both physically and institutionally. This characteristic of the system will largely determine how competition can be introduced and its success. Box 1-A presents the basic concepts of the electric power system. The bulk power system consists of the generation and transmission sectors. Distribution networks receive power from the transmission system for retail delivery to customers.

The System Today

The industry consists of over 3,200 entities supplying power to over 100 million residential, commercial, institutional, and industrial customers. Most electricity (76 percent) is supplied

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[5] Questions of risk and equity are critically important to the acceptance of competition, but they are not analyzed in this study because they are not directly related to the technology.

Box 1-A—Electric Power Systems

An electric power system is comprised of: **generating units** that produce electricity; **transmission lines** that transport electricity over long distances; **distribution lines** that deliver the electricity to customers; **substations** that connect the pieces to each other; and **energy control centers** to coordinate the operation of the components. Figure 1-1 shows a simple electric system with two power plants and three distribution systems connected by a transmission network of four transmission lines.

Fossil fuels, nuclear fission, and falling water are commonly used energy sources in the **electric generators**. A wide and growing variety of unconventional generation technologies and fuels also have been developed, including cogeneration, solar energy, wind generators, and waste material.

Generators typically produce 60 cycle/second (Hertz or Hz) alternating-current (AC) electricity with voltages between 12 and 30 thousand volts (kV). The frequency of all generating units on a system must be precisely synchronized. Generating units have **automatic voltage regulators**, which control the unit's voltage output, and **speed governors**, which adjust power output in response to changing system conditions. In addition to the real power that lights lamps and drives motors, an inescapable companion of alternating current, called reactive power, or VARs, must be monitored and controlled to maintain voltage.

Transmission lines carry electric energy from the power plants to the distribution systems. Most transmission in the United States consists of overhead AC lines designed to operate at a specific voltage between 69 and 765 kV. **Power transformers** raise the generator voltage to the transmission voltage and back down to the distribution network level (typically under 35 kV) at the other end. There are some segments of direct current transmission and underground cables for special applications, but these are less common than overhead AC lines.

An interconnected group of individual transmission lines comprises a **transmission system**. Virtually all electric utilities in the continental United States are connected to neighboring utilities through one or more lines of a transmission system.

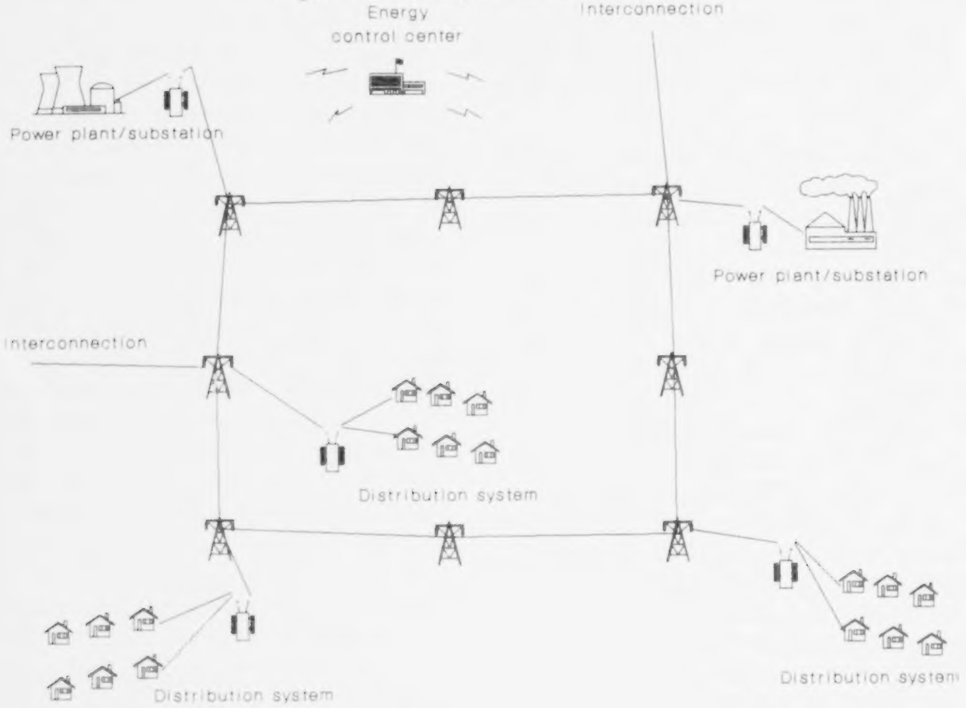
Coordinated operation of the power system components is implemented through institution of **control areas**. A control area is a geographic region with an **energy control center** (ECC) responsible for operating the power system within that area. One or more utilities may make up a control area. The control area in figure 1-1 is interconnected to two neighboring control areas through transmission lines.

Energy control centers employ a variety of equipment and procedures: monitoring and communication equipment called **telemetry** to constantly inform the center of generator output and system conditions; **computer-based analytical and data processing tools** which together with engineering expertise specify how to operate generators and transmission lines; and governors, switches, and other devices that actually control generators and transmission lines. The control center equipment and procedures are typically organized into three somewhat overlapping systems which are sometimes integrated in a full **energy management system** (EMS). They are the **automatic generation control** (AGC) system which coordinates the power output of generators; the **supervisory control and data acquisition** (SCADA) system which coordinates the transmission line equipment and generator voltages; and an analytical system to monitor and evaluate system security and performance, and plan operations.

by the 203 investor-owned utilities that generate the power they need, deliver it to their load centers over high-voltage transmission lines, and distribute it to their customers. Most of these utilities are vertically integrated, owning or controlling all the generation, transmission, and distribution facilities required to meet the needs of the customers in their assigned service area. Publicly owned utilities (Federal, State, and local) and consumer cooperatives also generate electricity (24 percent).

Nonutility generators (NUGs, including any producer of electricity not functioning as a public utility) are important in some regions and are starting to become a significant national

Figure 1-1—A Simple Electric System



SOURCE: Office of Technology Assessment, 1989.

factor. Statistics on NUGs are uncertain, but they appear to own about 25,000 megawatts (MW) of capacity out of a total of over 700,000 MW in the Nation.

The transmission system allows a utility to build a generating station wherever appropriate and deliver power to the load center, sometimes hundreds of miles away. In addition, it links utilities so that they can back each other up during emergencies and transfer power when it is economically advantageous to do so. The latter is normally accomplished by contract between utilities, specifying the power (megawatts), voltage, and the time period of the transfer, among other things. Transfers for economic purposes have become common in recent years.

The bulk power system is a combination of generating units and transmission lines that must be operated as a coordinated system. This requirement has governed the institutional evolution of the industry as well as the development of its physical system. The addition of nonutility generation to the system must be understood in this context.

In particular, the industry has developed an unusual level of cooperation among private companies as well as government agencies. All large utilities in the 48 contiguous States are members of one of nine regional reliability councils that form the North American Electric Reliability Council (NERC). NERC, through the utilities, issues standards and operating guidelines to improve overall coordination of utility procedures in the United States and

Canada and parts of Mexico. The regional councils coordinate planning and operations and exchange information on electricity demand and reliability. Table 1-1 describes the nine regional councils.

Some utilities have also formed "tight" power pools, which involve a high level of coordination and a central dispatcher to ensure the use of the most economic mix of generation throughout the pool. New England and New York are each essentially a single "control area." The Mid-Atlantic Area Council coincides with a single pool in addition to being a regional reliability council. Tight pools maximize the use of low-cost generation and minimize new construction and the cost of maintaining reserve capacity. Other utilities have formed "loose" pools to coordinate planning but with no contractual reserve requirements. In addition, several holding companies (e.g., American Electric Power) coordinate the activities of their subsidiary utilities as power pools. Utilities also make bilateral arrangements, and brokers match buyers and sellers of bulk power, usually for short periods of time.

In addition to pools, most utilities belong to an interconnected network, the largest operating unit. There are three such networks in the United States: the Eastern Interconnection (which extends nearly to the Rocky Mountains), Texas Interconnection (only in Texas), and the Western Interconnection. Within each of these three systems, all connected generators must be synchronized. Connections between two networks are accomplished through direct current interties to avoid synchronization problems.

Power System Technology and Requirements

The bulk power system (described in box 1-A) must be designed and operated according to certain physical principles of electricity. In particular, two key technical factors dictate many features of the bulk power system. **First, electricity flows at nearly the speed of light with virtually no storage of power in the system: electricity must be generated as it is needed.**[6] Automatic generation control (AGC) coordinates the operation of generators moment by moment to balance supply with demand. Control is maintained by individual utilities or by pools of interconnected utilities. There is usually a choice of generators to be turned up or down to meet changes in demand, each with individual cost and operating characteristics. Utilities spend considerable effort implementing "economic dispatch," or ensuring that the mix of units operating at all times represents the least-cost combination. They also must ensure that generating units will be ready when needed to follow the daily load cycle, that the transmission system is capable of carrying the loads, and that backup generating and transmission capacity is available in case of equipment failure.

Second, every flow of power from a power plant to a distribution system affects the entire transmission network, not just the most direct path. Electricity cannot be simply loaded onto a convenient transmission line and delivered, as trucks use the interstate highways to deliver products. If one utility sells power to another, they both must ensure that no components are overloaded on any of the paths available. The network connects many different utilities, and lines hundreds of miles away carry part of the load, a phenomenon called parallel path flow. Such flows can reduce the power that other utilities can place on their own lines. In some cases, a line may already be fully loaded, and the new power flow would overburden it. Therefore, the overall system's transfer capacity is constrained by the single most limiting transmission line.

Total system capacity is considerably less than the sum of the capacity of all lines in it. In

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[6] Pumped hydroelectric facilities store energy but not electricity. In effect, the system sees them as generating stations. Development of economic battery or magnetic storage technology for use within the distribution system could have important advantages for the electric power system.

Table 1-1—Characteristics of the Nine Electric Reliability Council Regions

NERC regions	States	Member systems	Projected 1988 installed capacity (MW)	1988 minimum capacity margin (percent)	Projected average annual growth 1988-97 (percent)	Net 1987 imports (billion kWh)
ECAR—East Central Area Reliability Coordination Agreement	MI,OH,WV,IN Most of KY and parts of VA,MD,PA	16 IOUs 2 Cooperatives	97,380	23.0	1.5	-20
ERCOT—Electric Reliability Council of Texas	Most of TX	6 IOUs 49 Cooperatives 20 Municipals 1 State agency	49,880	21.3	2.9	1
MAAC—Mid-Atlantic Area Council	DE,NJ,PA,DC, and parts of MD & VA	11 IOUs	48,582	19.0	1.8	25
MAIN—Mid-American Interconnected Network	IL, and parts of MO,MI,and WI	11 IOUs 1 Municipal 1 Cooperative	49,607	25.4	1.7	2
MAPP—Mid-Continent Area Power Pool	IA,MN,NB,ND, and parts of WI,SD,MT,MI,IL	11 IOUs 8 G&T Cooperatives 4 Municipals 3 Public Utility Districts 1 Federal agency	30,619	28.4	1.7	-8
NPCC—Northeast Power Coordinating Council	CT,ME,MA,NH,NY,RI,VT	17 IOUs 1 State authority	53,714	22.1	1.8	27
SERC—Southeastern Electric Reliability Council	AL,FL,GA,NC,SC,TN, and parts of VA,MS, and KY	16 IOUs 8 Municipals/public 2 Cooperatives 2 Federal agencies	139,334	20.0	2.4	9
SPP—Southwest Power Pool	AR,OK,KS,LA, and parts of MS,MO,TX and NM	17 IOUs 12 Municipals 8 Cooperatives 4 Government agencies	65,621	26.7	1.9	-4
WSCC—Western Systems Coordinating Council	AZ,CA,CO,ID,NV,OR,UT, WA,WY, and parts of NM,MT,SD,TX	19 IOUs 17 Municipals 16 Public power 5 Government agencies	123,022	31.5	1.8	38

SOURCE: NERC 1986 Annual Report; the 1988 Reliability Assessment: The Future of the Bulk Electric System in North America 1988-1997; and 1988 Electricity Supply and Demand for 1988-1997, October 1988.

addition to individual line constraints, the system imposes its own limitations because of reliability and stability concerns. Utilities generally operate the system with reserves sufficient to handle rapid shifts in power flows that occur when a transmission line or generating unit fails.

The capacity of the transmission system is not a fixed, exact limit that balances the utility's costs of providing reliability with the consumer's benefits of uninterrupted service. Rather, capacity is defined by utilities from operating practices and from trade-offs among several factors, including the operation of generating units as well as transmission lines. Capacity also varies over time, depending on factors such as air temperature. Determining whether an additional transfer can be accommodated often requires considerable engineering expertise, data, and analysis, and it is possible for different analysts to arrive at opposite conclusions.

Determining how to increase capacity is also complex. The system can be upgraded by increasing the capacity of individual lines; improving control of flows on the network; and adding new circuits. Table 1-2 lists technological options available to overcome specific limitations. Costs and benefits of implementing most of these options are highly site specific.

A variety of constraints can account for the capacity limit for any specific line. Lines can overheat with too much current, or high voltage can cause arcing in equipment. The limit also depends on a line's specific configuration, its relation to the rest of the system, and variables such as air temperature.

Improved control over the flow of power can increase capacity by bypassing constraints. Adjusting power output of generators on the network can maximize flow (but this can also result in noneconomic dispatch) and improving generator response times can reduce transmission reserves required in case of equipment failures. Phase shifting transformers, which act as valves to control individual flow, are gaining popularity. Transmission limitations can also be alleviated by control of reactive power.

Table 1-2—Technologies to Increase Transfer Capability

Remedies to individual line constraints
- *Voltage uprating*
  - Tower extensions
  - Upgrading insulators
  - Upgrading terminal equipment (circuit breakers, relays, transformers)
- *Current uprating*
  - Dynamic conductor rating
  - Sag assessment and monitoring
  - Restringing (live-line restringing)
  - Changing operating standards
- *Tower design and new lines*
  - Conversion to multiple circuit towers
  - High-voltage direct current lines

Remedies to steady state system operating constraints
- *Control of load division*
  - Phase angle regulators
  - Series reactance and capacitance
  - System reconfiguration
  - HVDC control features
  - Redispatch of generation
- *Reactive power management techniques*
  - Shunt or series capacitors
  - Shunt reactors
  - Static VAR compensators
  - Synchronous condensers
  - Generators as VAR sources

Remedies to contingency security and stability constraints
- *Improving generation response controls*
  - Generator tripping and fast runback
  - Fast valving
  - Braking resistors and load switching
  - Advanced excitation systems and stabilizers
  - Transient excitation boost
- *Improving transmission response controls*
  - High-speed reclosing and reducing clearing time
  - Rapid adjustment of network impedance
  - Fast acting phase angle regulators
  - Sectionalizing (adding switching stations)

SOURCE: Adapted from "Technical Background and Considerations in Proposed Wheeling, Transmission Access, and Non Utility Generation," contractor report prepared for the Office of Technology Assessment, by Power Technologies, Inc., March 1988, p. 6-2.

When large increases in capacity are required, it generally is necessary to add high-voltage lines. Not only can these lines carry large amounts of power, but they can raise the capacity of other lines if they eliminate constraints. The use of high-voltage direct current (DC) lines is increasing, even though considerable investment in conversion facilities is required at both ends, because control of direct current is much simpler than alternating current, and the lines themselves are cheaper.

Three R&D programs have the potential for significantly changing the electric power system. **High-power semiconductors** are already being applied to reactive power control, and further development may lead to switches for controlling power flow and to less expensive AC/DC conversion. Second, developments in **computing and data processing techniques**, including artificial intelligence and supercomputers, should have several applications for power systems, such as optimization of operations and power plant diagnostics and monitoring. Finally, in the long term, **superconducting materials** could improve the economics of the power system not necessarily in the transmission cables themselves but in generators, line control devices, and electric storage technology.

Technical Issues in Competition

The greatest challenge to increasing competition in generation and expanding transmission access is maintaining the high degree of coordinated planning and operation among bulk power system components. If coordination is not addressed with appropriate care, the system may experience increasing costs and decreasing reliability. Coordinated planning and operation of generation and transmission are required in performing three basic functions: following changing load, maintaining supply reliability, and transactions among utilities and generators, as described in box 1-B. **The key to coordination will be in defining workable institutional arrangements among participants in the power system. Some new physical facilities and improved analytical capabilities may be required, but all these functions can be provided with familiar technology**.

At present, a single utility or group of cooperating utilities is responsible for system planning and operations in a control area. As nonutility generation and transmission access increase, responsibility for coordinating the overall power system is separated from ownership of system components. Functions now routine to utilities would increasingly have to be unbundled and established by contract or other agreements among generators, purchasers, and carriers.

As in today's power systems, the arrangements may include formal contracts between parties as well as less formal agreements on standards and procedures. As unbundling increases, bilateral and multilateral contracts will be increasingly important instruments to communicate needs and define obligations of suppliers, transporters, and power purchasers. By specifying prices and performance, including penalties for failure to perform, contracts can help ensure that competitive supplies meet power system needs and mitigate uncertainty for all parties. However, contracts may have some shortcomings when compared to arrangements within a single organization, as in a vertically integrated utility. For example, given the overall uncertainty in the power industry, anticipating all terms and contingencies that a contract should cover requires extensive effort. Even with carefully crafted and flexible contracts, unexpected events outside the scope of the contract may occur.

How suppliers, purchasers, and transporters of power will respond to any competitive proposal is speculative. It is this individual behavior and how it is coordinated, however, that determines the real feasibility, reliability, and economic impact of increased competition in the electric utility industry. This study has identified no insurmountable problems of technical feasibility, although there are some substantial institutional challenges in developing new planning and operating arrangements. The ease or difficulty of implementing the institutional changes to meet technical requirements is, again, necessarily speculative.

Box 1-B—Coordinated Operations and Planning

An electric power system is composed of many interacting electrical and mechanical parts. Because of the complex and nearly instantaneous interactions between the components, their operation and planning must be carefully coordinated. For example, a decrease in output of one generator instantly changes power flows and voltages across the system, automatically causing other generators to increase their output. This could result in overloads or unacceptable voltages if not properly coordinated.

Coordinated operation and planning involves several procedures, ranging from moment-to-moment coordination of generator power and voltage output, to long-term planning and addition of transmission and generation. Together, these procedures control generation and transmission to perform three basic functions: **following changing loads**; **maintaining supply reliability**; and **coordinating transactions between utilities** (see table 1-3). These functions are performed in a way that seeks to minimize cost.

Following Load

Consumer demand for electricity changes continuously and somewhat unpredictably. Some changes tend to repeat cyclically with the time of day, day of week, and with the season. Others result from the vagaries of weather, economic conditions, and from the random turning on and off of appliances and industrial equipment.

Following load involves preparing generators for operation (e.g., warming them up) under **unit commitment schedules**, which reflect forecasted load changes over daily, weekly, and seasonal cycles plus an allowance for random variations. Some generators in a unit commitment schedule increase or decrease their power output either according to a schedule, following predicted loads; others are under **automatic generation control** (AGC) and **economic dispatch** to follow actual loads as required. Voltage control and reactive power devices on the transmission system and in generating plants are simultaneously coordinated to maintain system voltages as loads and supplies change.

Maintaining Reliability

From one moment to the next, any generator or transmission line may fail, either on its own or due to external influences (e.g., lightning strikes). Preparing for continued operation after equipment failure is called maintaining **security**. Security is maintained through unit commitment schedules and **security constrained dispatch**, which provide reserves of both generation and transmission. Together with the coordinated engineering of relays and circuit breakers used to isolate failed or overloaded components, they ensure that no single failure will result in cascading outages.

Ensuring sufficient availability of supplies, called maintaining **adequacy**, is also essential for reliability. In addition to unit commitment and economic dispatch for load following and security, maintaining adequacy involves coordinated **maintenance scheduling** of individual components and **planning** new generation and transmission capacity. Planning new capacity involves selecting the right mix and location of both generation and transmission to meet the needs of following load and maintaining security.

Coordinating Transactions

Nearly all utilities are interconnected with other systems, allowing for a variety of transactions. Transactions may take a variety of forms, including purchases and sales with neighboring utilities; purchases from suppliers within a utility's service area (e.g., an independent power producer); operation of jointly owned power plants; and wheeling of power. Except where contrary arrangements are specifically made, it is the responsibility of each utility to provide the power used by its customers without absorbing power from its neighbors or sending unwanted power to them. Coordinating transactions involves scheduling and control of generation to implement power transfers, as well as monitoring and recording transactions for billing or other compensation.

Some believe that in both the short and long term, competitiveness is likely to be detrimental to the cooperation among companies that is characteristic of the electrical power industry. Utilities routinely exchange information, coordinate planning, and provide backup for each other in emergencies. Companies that may be bidding against each other have less incentive to extend this level of cooperation. However, it is not clear how valuable this

Table 1-3—Operation and Planning Functions

Function	Purpose	Procedures involved
Following load		
Frequency regulation	Following moment-to-moment load fluctuation	Governor control Automatic generation control (AGC) and economic dispatch
Cycling	Following daily, weekly, and seasonal cycles (within equipment voltage, power limits)	AGC/economic dispatch Unit commitment Voltage control
Maintaining reliability		
Maintaining security	Preparing for unplanned equipment failure	Unit commitment (for spinning and ready reserves) security dispatch Voltage control
Maintaining adequacy	Acquiring adequate supply resources	Unit commitment Maintenance scheduling Planning capacity expansion
Coordinating transactions	Purchasing, selling, and wheeling power in interconnected systems	AGC/economic dispatch unit commitment

SOURCE: Adapted from F. Mobosheri, Southern California Edison, letter to Office of Technology Assessment, May 13, 1989.

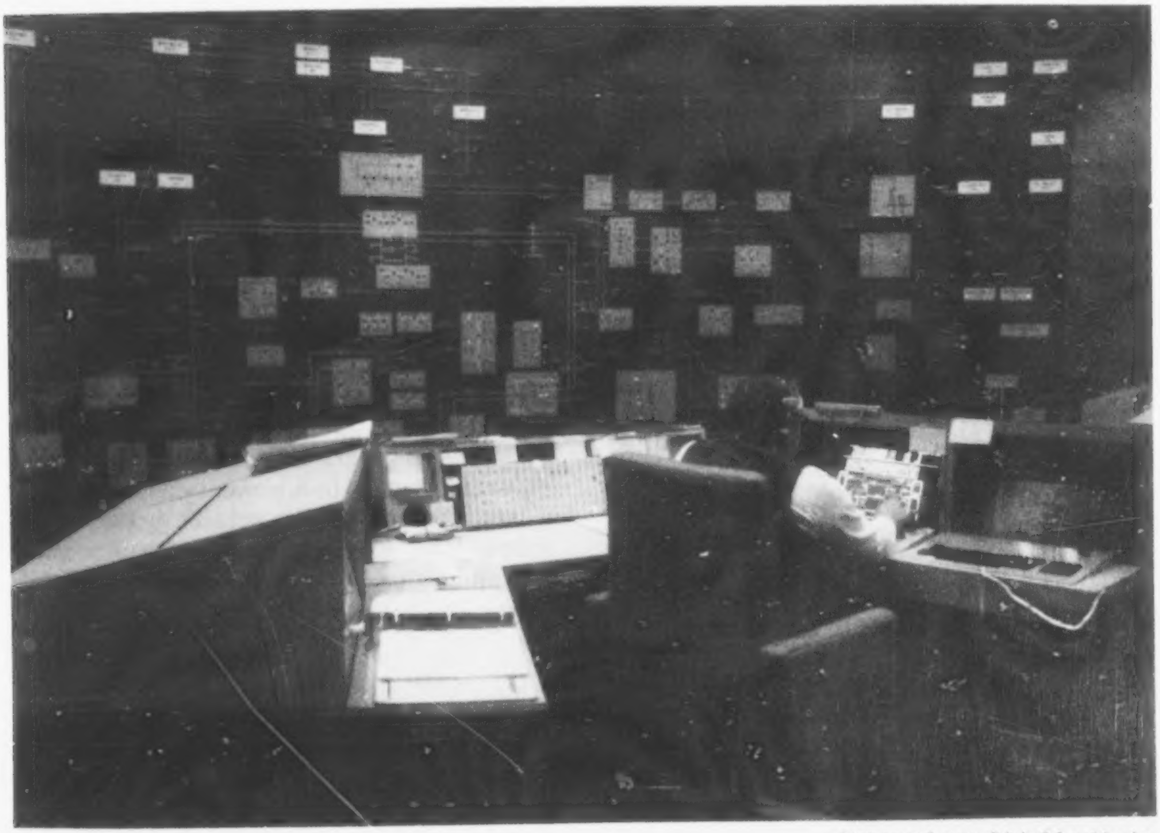

Photo credit: Casazza, Schultz & Associates, Inc.

Energy control center

cooperation is or how well contracts could duplicate actual activities.

Nonutility Generation

Nonutility generators are likely to use familiar equipment and fuels, and suitable controls for frequency and voltage can maintain output compatibility. Therefore, the equipment itself should not create undue problems if planning and operation are carefully coordinated.

However, it is not certain how difficult it will be to meet the technical requirements of coordinated planning and operation if competitive generation becomes widespread. These requirements do not preclude competition, but inattention to them will result in a needlessly unreliable and high-cost system, and it should be noted that the costs of meeting several of these requirements are quite uncertain.

Maintaining the efficiency of economic dispatch for load following will be a challenge. Competitive generating companies may operate more efficient and lower cost facilities than regulated utilities, but overall costs could still be higher if units are not dispatched to minimize total costs. For example, if generating companies contract directly with customers (retail competition) for the output of specific machines, then low-cost sources may be idled while a more expensive but nondispatchable source operates. Utilities, whether operating independently or in a pool, try to maximize the use of the lowest cost units. This interest will not automatically be duplicated in a system where many different entities own and operate generating units. To minimize operating costs under competition, centralized control of dispatch or other mechanisms to select the lowest cost of generation must be established. Contracts to establish control for economic dispatch may prove to work adequately, but they are likely to be less flexible than direct control by an integrated utility.

Maintaining reliability requires nonrevenue-generating functions such as keeping reserve units warmed up and immediately available for emergencies. Downtime for maintenance must be scheduled to minimize interference with system operation. Institutional adaptations will be necessary to perform these functions under competition. Increased reserve margins may be necessary to account for the uncertainty in how well these new institutional relations work. In addition, new monitoring and communication equipment may be needed to track and control the new unbundled transactions.

The costs of unbundling these services under competition are not yet known. Utilities now can simply lump the costs of these functions into their overall operating costs and have no need to determine exactly what each one entails.

Meeting demand growth with adequate and appropriate capacity is necessary for long-term reliability. **When utilities are evaluating bids for new generating capacity, they must not be forced to accept automatically the lowest price offered**. In the long run, the lowest costs will result if the bidding process provides an appropriate mix of operating characteristics. For instance, power generated to meet peaks usually costs more per kilowatthour because the plant is idle much of the time. If bids were to be accepted purely on price, proposals for nondispatchable (base load) generators would have a major advantage, but the bulk power system must have a large fraction of dispatchable generation to follow load. Reliability is another key factor affecting value. A power source that cannot be counted on because it is intermittent by nature or unreliable in operation is worth less than a facility that is almost always available when needed.

Power system planners are likely to need to continue specifying the attributes required of new generating units, including: type of fuel used; location; and ability to operate for base-load, intermediate, or peak use. Whether a competitive supply market will provide a full range of desired options and at what cost remains to be seen. Utilities may remain the preferred builder or the builder of last resort.

Ensuring that competitive generation will be completed as planned is another important challenge. Even with contracts for the right facilities, there is some uncertainty that the facilities will actually be completed as required because the contractor could encounter problems and withdraw. Utilities also can misestimate costs, but they are unlikely to cancel a plant that is needed to meet their obligation to serve. Depending on circumstances, either outcome (cancellation or completion of the plant) could be correct; institutional arrangements will need to be designed for flexibility to encourage the right response. Some possible approaches include specifying liquidated damages for nonperformance and allowing the purchasing utility to take over an abandoned project. Both reduce the incentive to abandon a construction project when faced with some cost overruns, and give the utility additional resources for acquiring needed supplies.

One factor that may ease the implementation of competition is the trend toward smaller generating facilities close to the load centers. Small facilities usually entail less uncertainty over construction leadtime and cost. Not only are the risks of failure less for small facilities, but the consequences of individual failures are minor.

Transmission Access

As the number of players in the electric power industry increases, demand for wheeling will increase. Competing generators will want to sell to whomever will pay the most, whether that is the local utility or a distant customer, and some consumers will want to shop for supplies. In either case, they will require transmission services. Some proposals would require a transmission company to wheel for any and all customers unless it can show that it would be infeasible, for instance if their system has no additional capacity. There would be established a rebuttable presumption that transmission service could be provided.

The technical challenges of increased transmission access will be significant. As discussed above, available capacity on transmission systems is difficult to determine. It depends on the specific conditions at the time transmission is desired, the reliability and longevity levels selected by the utility, and the parallel path flows that will result. Therefore **disputes over the feasibility and cost of wheeling may be difficult to resolve**. In addition, control of transmission loading currently is effected largely through control of generation. As lines approach full capacity, increased demand is met by shifting to generating units that do not require these lines, even if they are more expensive to operate. If independent generators have access to the system, such shifts could be more difficult to manage. Also, if a substantial amount of the power flow on the transmission network is not dispatchable, balancing demand with supply for the remainder of the load will be more difficult. Finally, long-term planning for transmission capacity additions would be complicated by the uncertainty of where new generating units were going to be located and where their power would be delivered.

To a large extent, the success of implementing increased transmission access depends on developing workable definitions of obligations and rights of all parties and the institutions to carry them out. Various wheeling arrangements are possible, depending on the types of power suppliers, purchasers, and transporters and the specific agreements between them. Wheeling agreements must specify the amount of advance notice and other conditions under which the transporter can halt a transaction and the amount of advance notice buyers and sellers must give the transporter before increasing or decreasing the amount of power to be wheeled. These rights and obligations, while critical for determining technical feasibility and economic impact, also raise fundamental questions of equity and appropriate levels of cooperation.

It should be noted that it is not clear how much expansion of the transmission system will be necessary or practical. The decrease in surplus generating capacity in all parts of the country will reduce the availability of inexpensive bulk power. The apparent reversal of the trend toward large, remote generating stations in favor of smaller generators located close to load centers, if continued, will also reduce future needs. In addition, the costs of siting and constructing transmission lines may exceed their benefits. Major upgrades and new lines frequently encounter opposition, as discussed below. New technology, such as fuel cells or small photovoltaic systems, could completely revamp the way we generate and deliver power. Thus it is not clear that massive upgrades are inevitable, especially in the long-term, though it is likely that some continued growth will be required.

CHANGE AND THE BULK POWER SYSTEM

A variety of futures has been espoused for the electric power industry, including different forms of competition. This assessment presents five scenarios based on recent proposals representing the major themes in this debate. The scenarios provide a framework for analyzing technical considerations. In particular, they focus on competition in generation and access to the transmission system. Table 1-4 lists the main characteristics of the five scenarios.

Scenario 1 assumes that with some modifications to the current regulatory process, the existing organization for supplying electric power will be the most effective. Proponents of this approach believe that the major problem is that utilities will be reluctant to build adequate new capacity to meet future growth. Therefore, the "regulatory bargain" is strengthened by reassuring utilities and their investors that a reasonable return on investment will be allowed. A potential vehicle for this reassurance would be "rolling prudence"—prior approval by the State utility commission of the need for new facilities and periodic progress reviews during construction. If there is a problem, adjustments can be made or the plant canceled before costs have become too high, but the utility would be guaranteed recovery of all costs already certified. In addition, minor modifications to PURPA regulations would be implemented to correct perceived imbalances in avoided-cost pricing for QFs. Competition could continue to grow incrementally as an alternative, but no special measures would be implemented to promote it. Transmission access would be voluntary.

Scenario 2 expands the environment for competition through increased access to the transmission system for utilities, QFs, and IPPs. It adopts a broad public interest standard for issuing wheeling orders, including requests by large retail customers shopping for the best price. There would be a presumption that the capacity to wheel exists, and the utility denying the services would bear the burden of showing otherwise. Scenario 2 also broadens the definition of qualifying facilities. Changes to PURPA, the Public Utility Holding Company Act (PUHCA) and the Federal Power Act (FPA) would be required. The industry structure and regulation would remain much the same. Prime responsibility for operation and development of the bulk power system would remain with utilities.

Scenario 3 would create a competitive generating sector incrementally. When a need for new generating capacity is established, a utility would solicit proposals to supply it. The utility would select the best bids based on price and other factors, purchase the power under contract, and distribute it to customers. Participating utilities would have to guarantee transmission access for other generators, but would not be required to provide wheeling for retail

Table 1-4—Summary of Alternative Scenarios

Scenario 1 Strengthening the Regulatory Bargain	Scenario 2 Expanding Transmission Access and Competition in the Existing Regulated Utility Structure	Scenario 3 Competition for New Bulk Power Supplies	Scenario 4 Competition for All Bulk Power Supplies	Scenario 5 Common Carrier Transmission Services in a Disaggregated Industry Structure
• Industry consists of a mix of vertically integrated utilities, IOUs, public power, cooperatives, Federal power authorities, self-generators, QFs, and IPPs. • Existing regulatory structure with State preapproval of new generating projects and periodic prudence reviews during planning and construction. • Negotiated transmission access arrangements. • Traditional system coordination and control by integrated utilities or control centers. • Prices set by regulatory proceedings and cost of service. Transmission prices and wholesale rates set by FERC (including approval of negotiated IPP power purchases). State oversight of retail rates and PURPA implementation. • Federal and public power agencies and cooperatives affected only to the extent State law provides.	• Industry consists of existing mix of entities. • Existing regulatory structure with wider QF eligibility under PURPA including full utility ownership/control of QFs (may require amendment of PURPA). • New Federal wheeling authority under a public interest standard for wholesale and retail transmission access (requires amendment of the Federal Power Act). • Traditional system coordination and control by integrated utilities or control centers with contracts for unbundled services. • Prices set by regulatory proceedings and cost of service. Transmission prices and wholesale rates set by FERC (including approval of negotiated IPP power purchases). State oversight of retail rates and PURPA implementation. • Federal and public power agencies and cooperatives affected only to the extent State law provides.	• Existing mix of generating entities expanded by IPPs and unregulated utility generating subsidiaries. • Existing regulatory structure with market-based rates for new competitive generation. Utilities use all source procurement for new bulk power needs. Contracts awarded to lowest cost supplier with consideration for non-price factors. • Transmission access provided by utilities as a bidding condition, or by privately negotiated arrangements, or under new Federal public interest wheeling authority (no retail wheeling). • Traditional system coordination and control by integrated utilities or control centers. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Retail and transmission prices set by regulatory proceedings. Wholesale power prices set through competitive procurement except for cost-base plants built by utility as last resort supplier. State and Federal regulators oversee terms and conditions of wholesale sales. • Federal and public power agencies, and cooperatives can participate in competitive generating sector to extent provided by Federal and State law and policy.	• Industry structure: Ownership of competitive generating sector segregated from transmission and distribution sectors. • New Federal and State regulatory systems. Price and entry regulation of generation sector replaced with competitive market. Continued regulation of transmission and distribution utilities and retail sales. • Revised Federal wholesale wheeling authority. Transmission utility to plan for and provide nondiscriminatory access for bulk power supplies. • Most of traditional utility system planning and coordination taken over by transmission and distribution entities. Competitive generators plan and build generation. Transmission operator assumes responsibility for bulk power system control and operation. Distribution utility retains retail obligation to serve. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Bulk power prices set by market through bidding, negotiation. Transmission and retail prices are set by regulatory proceedings. Some State and Federal oversight of competitiveness of generation markets and prudence of bulk power contracts. • Federal and public power agencies, cooperatives can participate in competitive generating sector to extent provided by Federal and State law and policy.	• Ownership and control of existing integrated utility industry is disaggregated into separate generation, transmission, and distribution segments. • New Federal and State regulatory system. Price and entry regulation of generation replaced with competitive markets. Distribution utilities' services and retail prices remain regulated. Transmission prices and activities are strictly regulated. • Transmission sector operates as a common carrier providing nondiscriminatory access to all wholesale and retail customers. Reasonable conditions on reserving transmission services may be imposed. • Bulk system planning and coordination is split among generation, transmission, and distribution entities. Generators identify, plan, and build new generation in response to market signals. Transmission utility assumes responsibility for reliability of bulk system operations. Responsibility for estimating demand and securing adequate power supplies rests with distribution utilities. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Bulk power prices set by market. Transmission and retail prices are set by regulatory proceedings. Some State and Federal oversight of competitiveness of generation markets and prudence of bulk power contracts. • Federal and public power agencies, cooperatives can participate in competitive generating sector to extent provided by Federal and State law and policy.

SOURCE: Office of Technology Assessment, 1989.

customers. Some modifications to the FPA, PURPA, and PUHCA would be required.

A two-tiered pricing system would result: competitive power under minimal regulation; and power from existing generation under the current State-Federal regulation. Transmission and distribution prices would remain regulated. Scenario 3 differs from recent proposals by FERC in that utility participation in bidding programs would be mandatory, and transmission access is guaranteed.

Scenario 4 would drastically restructure the industry to create a competitive generating sector over a short period of time, rather than incrementally as in scenario 3. Utilities would spin off their generating facilities and activities into affiliates or even independent companies. Transmission and distribution could, but would not have to, be separated from each other and would remain heavily regulated. Safeguards would be needed to prevent self-dealing and cross subsidization in cases where a generator was bidding to supply power to a transmission/distribution affiliate.

Competitive companies would generate the power and sell it to regulated transmission and distribution companies (which could be either combined or separate). Transmission and distribution utilities would be responsible for contracting for adequate power to meet expected demand at all times. Most of the other coordinating functions that integrated utilities now perform internally, such as dispatch and system control, would be arranged by contract. The transmission companies would have an obligation to maintain adequate capacity to wheel power as required for regional needs, their own distribution clients, and for generating companies selling directly to retail customers. Wheeling for retail customers would be voluntary. This scenario would involve a substantial reevaluation and redistribution of rate-base assets in a transition period, entailing major public policy issues.

Scenario 5 would completely separate utilities into generation, transmission, and distribution sectors. Entry into the generation sector and bulk power pricing would be left to market forces. Electricity would be supplied under long-term contracts and spot sales by competitive generators. Retail prices would still be regulated. Transmission utilities would be converted into common carriers (i.e., providers of a nondiscriminatory service based on approved wheeling tariffs for all parties on request). All customers would have the option of obtaining their power from any willing supplier with the assurance that such power would be delivered under reasonable terms. Transmission and distribution companies would be obligated to plan for adequate capacity for all anticipated needs, as in scenario 4.

Technical Implications of the Scenarios

Any proposed change raises uncertainty as to how well the new system will work, though competitive changes to date have been assimilated. **There is no point at which increased competition becomes clearly infeasible. Rather, increasing competition expands the institutional modifications required and raises the uncertainty of success in maintaining reliability and improving economics.** The feasibility of these scenarios depends largely on developing new institutional relationships among suppliers, consumers, and transporters to preserve the coordinated operation and planning of the power system. Implementing these new relationships is likely to require some new physical facilities and improved analytical capabilities. Without careful preparation, changes to the institutional structure of the industry can affect the operation of this system in ways that are not necessarily obvious.

Scenario 1 would produce only evolutionary changes in competition and industry structure. Utilities would continue to build most new capacity and coordinate the power system. Thus no major technical challenges are likely to appear as a result of implementing scenario 1.

The major technical impact of scenario 2 will be an increase in the required level of analysis of transmission availability and costs. One difficulty with increasing access to the transmission system is that transmission capacity is a matter of trade-offs and assumptions, not an objectively defined limit. Additional information and analysis of availability, costs, and reliability of transmission services would be needed by the operators of the transmission networks, suppliers of power including utilities and nonutility generators, and regulators. In addition, some increase in system complexity is expected (with more actors and more transactions), resulting in a need to upgrade control centers and AGC systems. New procedures for dispatch and scheduling of wheeling would be required. Additional generation and transmission reserves might be needed to account for increased uncertainty or loss of coordinated control.

The technical challenges of scenario 3 would be similar. Control of generation will be more complicated if many different entities are responsible for generation. Analysis will be required to operate the system most efficiently and allocate costs and benefits. Procedures will need to be developed to ensure economic dispatch. Regulators and utilities will also have to quantify the value of supply characteristics such as dispatchability, fuel diversity, location, and risk of project failure. Reserve margins for both generation and transmission might have to be increased to allow for uncertainties, though this might be balanced by a trend toward smaller, dispersed generating units.

Scenario 4 differs from 3 largely in the rate and extent of change. Instead of incremental competition with just new generation (which is only several percent per year), utilities would rapidly spin off their generating facilities. Substantially new operating and planning procedures would have to be developed and implemented rapidly. Maintaining coordinated generation and system reliability will present significant challenges. Rapid change is riskier than gradual change because mistakes can become widespread before they are recognized. If not done well, the result could be lower reliability and higher costs.

Scenario 5's common carrier wheeling and complete separation of generation, transmission, and distribution into separate companies compound the risk and uncertainties of scenario 4. Coordinated operation of the bulk power system will require careful definition and unbundling of services for wheeling as well as generation. Transmission companies will have to be particularly alert to potential problems since they will have only contractual control over generation and possibly incomplete control over the use of the transmission system. As in scenario 4, the rapidity of change greatly increases the likelihood of making expensive mistakes.

Regional Differences

Conditions that will affect the desirability and feasibility of competition vary widely across the country. Some impacts will be local and utility-specific.

Scenario 1 would affect existing State regulatory programs though some States have already incorporated elements such as prior review and certification of new capacity needs. Most States have allowed recovery of prudent investment on abandoned plants and require utilities to submit long-range plans for generation and transmission requirements. However, no State has initiated all the provisions of scenario 1. Some increase in regulatory activity would be required, especially in States with traditional approaches to ratemaking (primarily in the West and Southeast). Lowered avoided cost payments might reduce QF growth, particularly in California, Texas, and Colorado.

Scenario 2 could have significant local impacts. The encouragement of QFs and greater access to the transmission system could increase wheeling, though the degree cannot be predicted confidently. Power wheeling from low-cost suppliers to high-cost areas should increase, possibly reducing rates in those areas, depending on local conditions. If scenario 2 results in a large net increase in system demand, the stresses on already heavily loaded systems would increase and create pressure for new capacity. The areas most likely to be seriously affected are the East Central Area Reliability Coordination Agreement (ECAR), the Mid-Atlantic Area Council (MAAC), the Northeast Power Coordinating Council (NPCC), the Electric Reliability Council of Texas (ERCOT), and the Western Systems Coordinating Council (WSCC).

The impacts of scenario 3 will depend largely on how competitive procurement is implemented, and will not be great for at least a decade, especially in States with little need for new generating capacity. Specific provisions in solicitations and nonprice considerations can determine who is willing to bid. Small generators and renewable energy could be disadvantaged unless protected. Regional price discrepancies should diminish over time as low-cost power is bid up and wheeled, displacing high-cost suppliers. Areas that become heavily dependent on NUGs must be especially careful to properly integrate these facilities or they risk lowered reliability. State regulatory activity could increase significantly.

Scenario 4 would accelerate the impacts of scenario 3, and introduce questions of equity, the viability of competition, and the role of State regulation. Prices to consumers are largely unpredictable if this scenario is imposed rapidly. Some regions may not have enough viable suppliers to sustain a competitive market. In regions with no surplus generating capacity, low-cost power from older plants could suddenly increase in price. Newly independent generators could also flee an existing service area to sell in a higher price region, creating instability in the supply. Regions with a strong transmission network arrangement might have an advantage in creating the necessary institutional infrastructure for separate transmission utilities. Thus costs and benefits are likely to vary widely.

Scenario 5 shares many of the impacts of scenario 4, but is even more extreme and unpredictable because there are few precedents for determining how a common carrier transmission network would work. Multi-State common carrier companies will require considerable attention from Federal and State regulators.

Economic and Institutional Impacts

While it can be stated with reasonable confidence that any of the scenarios can be made to work if carefully defined, increased competition involves significant economic uncertainties. **Success depends on the ability of competitive suppliers to function more efficiently than utilities to overcome any additional costs from increased difficulties of coordination. It is not clear how extensive the opportunities for improved efficiency are, how costly maintaining coordination will be, or how much wheeling would increase if a "broad public interest standard" for transmission access is implemented.** Thus the economic merits of scenarios 2-5 cannot be predicted accurately.

It is likely that the costs and benefits would be unevenly distributed, depending on specific utility and local factors. Scenarios 4 and 5 present the greatest uncertainties, especially during the transition phase. Balancing the interests of consumers, utility shareholders, and new entities will be particularly difficult if existing, rate-based assets are spun-off to competitive generating companies.

The "rolling prudence" of scenario 1 could result in greater reassurance to utilities interested in building large coal or nuclear plants, but a survey of utilities did not provide much support for the concept. Only a few believed that rolling prudence would eliminate regulatory uncertainty, which is only one of several disincentives working against these plants.

Under scenarios 3-5 utilities will have to unbundle many of the services they now provide internally—dispatch, maintenance scheduling, new construction, etc.—and arrange to have them accomplished under contract with other companies. If contracts are prepared carefully they may serve as well as internal control, but they will require considerable foresight and analysis, and may be less flexible in meeting changing needs.

SITING, ENVIRONMENTAL, AND HEALTH ISSUES

Increasing competition and opening up the transmission grids raise many public policy issues beyond the technical and institutional feasibility of accommodating these changes. Three of the most significant and potentially contentious of these issues are: transmission line siting, environmental impacts, and potential public health effects of electric and magnetic fields.

Siting

There is a widespread perception in the industry that siting new electric transmission lines has become almost impossible because of the obstacles encountered in the process of regulatory review and approval. While there are a number of well-publicized cases where construction of transmission lines has been delayed or prevented as a result of public opposition in the siting process, these cases are the exceptions, not the rule. The process of gaining approval for transmission line construction has become more formalized as opportunities have been provided for public involvement and greater scrutiny of potential environmental and social impacts of proposed projects. Competition for land to route transmission lines has become more intense and right-of-way costs are increasing. Nevertheless the Nation's transmission networks have continued to grow. According to a survey of State agencies by the National Governors' Association and the National Association of Regulatory Utility Commissioners, more than 515 requests for transmission lines have been filed with State agencies in the last 10 years, and all but 18 have been approved.[7] The survey did not distinguish between major, high power lines and short, noncontroversial lines, but it shows that the licensing process generally is still a routine (though sometimes difficult) process.

Planned investment in new transmission lines has been declining. At least part of the reduction in planned new transmission projects reflects the completion, deferral, or cancellation of associated generating facilities. Eventually, however, new and expanded transmission systems will have to be built to provide an adequate and reliable power supply, whether a competitive future path is taken or not. The challenge for industry and regulators is to create a system which plans for and encourages needed expansion while at the same time accommodating other competing interests, and resolving or minimizing conflicts.

Environmental Impacts

Overall, neither expanded competition nor increased transmission access is inherently incompatible with national environmental objectives. None of the scenarios is demonstrably preferable on environmental grounds, but uncertainty over impacts increases with the degree of change from the status quo.

Decisions over the future structure and composition of the electric power industry in the United States have direct environmental impacts from shifts in the choice of fuels used for generation and in requirements for increased transmission with increased competition. However, it is not clear at this point what shifts would occur.

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[7] Public Service Commission of West Virginia, "State Survey of Transmission Certification and Siting, and Planning Processes," unpublished summary, Nov. 13, 1987. This document provides preliminary results of the NGA-NARUC survey of State utility and siting commissions.

One possibility is that competition could encourage the protracted operation of older, dirtier generating facilities which otherwise would have been retired by a utility.[8] Competitive generators may not use the same fuels and generating technologies as traditional utilities, which would result in a different mix of pollutants. The first solicitations for competitive generation in Massachusetts suggested a wide variety of fuels will be used, including coal and trash. Alternatively, if competition discourages the development of environmentally benign but economically risky alternative energy technologies, the net effect would be negative for the environment and human health.

However, none of these arguments is conclusive, and competition could prove beneficial for the environment. Many observers believe that reliance on competitive bidding for new generation could cause a shift toward natural gas and oil (though under some schemes the purchasing utility could express a preference for specific fuels). Both have been cleaner fuels than coal, but are not entirely devoid of pollutants. Furthermore, recent technology such as fluidized bed combustion permits coal to be burned very cleanly even in small plants, suggesting that air pollution can be tightly controlled under any scenario. Thus the environmental impacts are not a clear function of the competitiveness of the industry structure, but the possibility exists for some significant unintended effects.

Transmission line construction, operation, and maintenance also create direct and indirect impacts on the environment. Concerns often center on land use, aesthetics, destruction of forests and wildlife, corona discharges, and the biological effects on human health (discussed below). These are the primary issues affecting siting disputes. Several of the scenarios are likely to increase demand for transmission services. As capacity is expanded (new lines and greater use in existing corridors) the number of such disputes and the environmental impacts of transmission will increase.

Health Effects

Until relatively recently, there was little or no scientific evidence that power frequency fields could pose a threat to human health. However, laboratory studies have now demonstrated that even relatively weak electric and magnetic fields have effects on living cells and systems. Scientists are still investigating whether these effects have public health implications. In addition, several recent epidemiologic studies have suggested an association between exposure to electric and magnetic fields and cancer. While these epidemiologic studies are controversial and incomplete, they do provide a basis for concern about effects from exposure.

The research results to date are complex and inconclusive. Many experiments have found no differences in biological systems that have been exposed to fields and those that have not. **It still is not possible to demonstrate that such risks exist, and they may not. However, the emerging evidence no longer allows one to conclude that there are no risks**.

If power frequency fields do prove to pose human health hazards, the implications for the electric power industry will be great whether competition is encouraged or not. Already, health effects are one of the most prominent concerns raised by people living near existing or proposed transmission lines. However, it is important to recognize that exposure from high-voltage transmission lines is only one, perhaps minor source. Exposure to local electric distribution lines, appliances, lighting fixtures, and wall wiring are more common and could play a more significant role in any public health risks.

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[8] The argument is that many old, fully depreciated plants are no more expensive to operate than new plants, but rate regulation provides limited incentive to keep them on line. If a utility can spin off this asset, as in scenario 4, the value of the plant would rise considerably, and it would be worth operating longer. A counter argument is that competition will drive down the costs of new plants, making older plants less competitive. Individual cases are likely to hinge on specific costs as well as on how competition is implemented.

POLICY

Even without legislative action, the competitive generation segment in the electric power industry is growing. Also FERC and the States are incorporating a greater reliance on market forces in existing regulatory standards and procedures. These trends are likely to continue. There is no crisis mandating immediate action by policymakers. However, the structural changes sought and the way in which they are effected have major public policy implications worthy of congressional consideration. If Congress wishes to encourage increased competition and transmission access, several technical and institutional changes could help ensure that the electric power system operates reliably and economically.

The policy options discussed here are not directed at implementation of the OTA scenarios.[9] Rather, the policy discussion focuses on three areas of potential congressional concern: the technical and institutional changes that must occur to assure that the reliability and economy of operation of the bulk power systems do not suffer in any competitive transition; the lack of information, analysis, and experience to support decisionmaking about electric power industry structure and regulation; and the broad public policy questions that will be central to any debate over fundamental changes in the regulation of electric utilities and bulk power markets.

Maintaining Reliability and Economy of Operation

The key technical/institutional issue that has been identified in this analysis is how to maintain the coordinated planning and operation of the bulk power systems as competitive trends result in a growing separation of ownership and operation of generation and transmission facilities. Responsibility for establishing an adequate technical framework to support a more competitive generating sector or increased transmission access will fall largely on the utilities, the competitive generators, and several voluntary and professional associations. Federal and State policymakers can further some of the required changes and will have a major oversight role in determining whether the changes are proceeding in the public interest.

Technical Requirements for Competitive Generation

Additional information and research are needed to establish a firm technical foundation in the key areas of: a) load following and system support and b) coordinated planning. Unbundling generation and bulk power system support functions will require development of new standards, analytical methods, and data collection and accounting practices that are acceptable to all or most participants. Additionally, the extent of system support and reliability services that integrated utilities now provide internally or cooperatively will have to be defined and the costs evaluated so that they can be properly allocated in an unbundled competitive system. Appropriate contractual arrangements or regulatory guidelines will need to be devised to assure compliance with load following and other responsibilities and to require information sharing.

Federal and State regulatory agencies can aid in the development of adequate technical and institutional responses to the challenges created by unbundling through:

1. establishing clear guidelines for determining and allocating the costs of providing unbundled services and system support;
2. establishing minimum or standard bulk power contract provisions that provide for the necessary technical conditions of gen-

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[9] Scenario 1 could be implemented with State action and some Federal regulatory changes, but scenarios 2 through 5 would require Federal legislation and corresponding changes in State law and regulation.

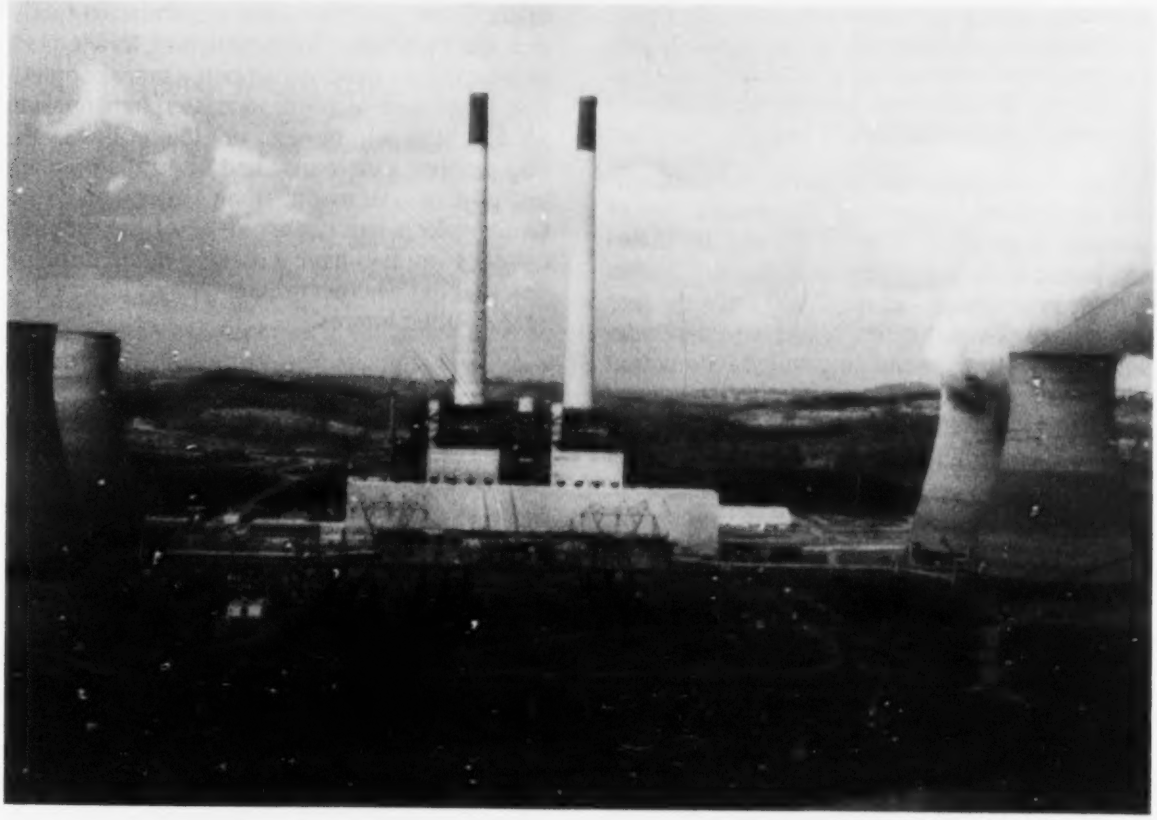

Photo credit: Casazza, Schultz & Associates, Inc.

Coal-fired power plant

eration control, coordinated operations, and system support obligations; and

3. requiring that competitive supply contracts contain adequate enforcement and default terms to assure that power supplies will continue to be available.

In addition, revised planning methods may be required to integrate competitive power supplies into utility resource plans and operating guidelines and to accommodate the new uncertainties that they may bring. State regulators could change their utility planning programs to require more detailed information on resource needs and technical standards. Regulatory agencies may have to adopt a systematic process to ensure that reasonable choices are made for generation type and location, and transmission capacity, perhaps requiring expanded State involvement in planning.

Technical Requirements for Transmission Access

A greater diversity among generators and bulk power customers and an increase in wheeling will create a need for new methods of coordination, capacity evaluation, compensation for unbundled transmission services, and regulation. The actions that could be taken by Federal and State governments include:

1. funding research needed to resolve common problems in transmission availability standards, costing and pricing of transmission services, and minimum contract provisions for wheeling services;
2. reviewing and modifying existing regulatory practices to assure effective oversight of transmission contracts, pricing, and impacts on other interconnected systems;
3. encouraging consideration of overall regional transmission capacity needs in utility transmission planning activities;
4. requiring FERC to act promptly in setting guidelines or rules for determining and allocating the costs of unbundled transmission services, including reliability support; and
5. requiring FERC or DOE to perform more detailed study of the technical and institutional changes required to provide transmission access in a more competitive industry and to report back to Congress on any desirable legislative changes.

Strengthening the Transmission System

No systematic review of the Nation's transmission system's constraints and bottlenecks has been conducted recently to determine whether bulk transfers can be increased or how much additional access could be easily accommodated. Congress could commission a new detailed study of the capability of the transmission systems to serve projected needs and to respond to emergency situations. Two earlier federally sponsored studies of the Nation's power grid proved useful for improved system operations, and an updated study could be essential for potential industry restructuring, future planning, and regulatory oversight. New analytical techniques for measuring transmission capacity and availability are also needed.

Congress could also encourage better information gathering and more frequent assessments of transmission capacity needs by FERC and DOE in cooperation with State utility commissions. These efforts could complement ongoing efforts by industry groups, such as NERC.

Better Information and Analysis for Public Decisionmaking

This report has noted a dearth of information, analysis, and experience to support policy decisions over whether further competitive changes should be adopted and how they could best be implemented. Additional research and information are needed on:

- bulk power markets,
- transmission system capabilities,
- nonutility generation,
- potential efficiency gains from expanded competition,
- alternatives to competition to achieve similar cost savings, and
- impacts of competition on other Federal energy and environmental goals.

The uncertainty resulting from this lack of information could seriously hamper Federal and State regulators' efforts in: 1) assuring the fairness and competitiveness of the bulk power market, 2) assuring continued reliability of the system, 3) protecting the interests of consumers, and 4) achieving other energy policy goals. The uncertainties also could hinder efforts of power buyers and sellers to make arrangements for competitive bulk power sales and wheeling transactions that are adequate to protect system reliability.

Congress could direct DOE and FERC to expand their information gathering and analysis activities to provide more accurate, timely, and usable information on bulk power transactions and wheeling. The existing competitive experiments could be more rigorously analyzed to provide necessary data to proceed to the next stage of competition. For example, the Southwest experiment was not conducted in a way that provided this information. The initial efforts by several States to initiate bidding procedures also could provide critical information if analyzed promptly.

Finally, it is important to resolve concerns over the possibility that exposure to electric and magnetic fields may pose human health hazards no matter how the electric power industry evolves. If such hazards exist, health considerations will likely create additional constraints on siting of transmission lines. Funding for additional research on health effects and potential remedial measures could resolve some of the uncertainties and permit better decisions on protecting public health and on siting transmission lines.

Expanding Competition—Institutional and Public Policy Issues

Proposals for changing the regulatory and institutional structure of the bulk power industry raise many legislative issues. Most major strategies for significantly expanding competition will require congressional action to eliminate institutional and regulatory problems and to assure orderly development. It is also possible that growth of a competitive generation sector may be so rapid that congressional or regulatory action may be required to allow the regulated transmission and distribution sectors adequate time to adjust their own operations and procedures. Among the major public policy issues likely to arise under alternative paths of industry change are: encouraging broader market participation, expanding transmission access, and establishing an appropriate balance in Federal and State regulation of electric power.

Enhancing Bulk Power Competition

Congress can affect the rate of increase of competitiveness even without legislation by encouraging or discouraging FERC's proposed rulemaking and other regulatory initiatives. In addition, Congress could direct FERC to prepare a report evaluating the effectiveness of the existing limited experience with competitive markets before revising Federal utility regulation on a broad scale.

If Congress chooses to encourage the trend toward competitiveness, it could remove some of the constraints imposed by existing law on potential participants in a competitive generating sector. Modifications to the Federal Power Act, the Public Utility Regulatory Policies Act, and the Public Utility Holding Company Act have been suggested by utility and independent power groups as a means to attract potential new competitors in bulk power markets. Generally, the proponents argue that the amendments would lessen constraints created by either direct limitations on participation by utilities and others in the independent generating sector or by disincentives associated with the regulatory requirements imposed on public utilities. It should also be noted, however, that changes in these laws would be controversial and could undercut other important public policy goals.

Expanding Access to Transmission Services

Under existing law, most transmission access and wheeling arrangements are the result of voluntary, negotiated agreements. Pressures for utilities to allow access to their grids will grow with the competitive bulk power market. But it is not clear that under existing laws transmission access will expand rapidly enough so as not to be a constraint on market participation. FERC has only limited authority to order utilities to provide wheeling services. If Congress chooses to address transmission access problems, there are several alternative approaches available. Congress could direct FERC to change administrative processes and transmission pricing policies to encourage access. Congress could amend the FPA and PURPA to provide more expanded wheeling authority. One possibility would be to repeal the more restrictive aspects of the existing wheeling provisions and allow FERC to order wheeling in appropriate cases under a broad public interest standard. Congress might also consider whether a more direct Federal role is needed in encouraging expansion of transmission capacity though authorization of more cooperative State planning efforts and/or expansion of regional transmission services provided by Federal power agencies.

Striking a Balance Between State and Federal Jurisdiction

Federal jurisdiction over electric power regulation has been growing at the expense of State regulation. This trend will accelerate under a competitive bulk power market structure unless Congress changes existing laws to limit or override Federal court and agency decisions. Examples of possible congressional remedies include: returning jurisdiction over instate wholesale transactions to State authorities, giving States jurisdiction over instate wheeling activities, and requiring FERC to defer to State regulators in matters of prudence and resource planning.

Chapter 2

An Overview of the Changing Electric Power Industry

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Chapter 2

An Overview of the Changing Electric Power Industry

INTRODUCTION

This chapter provides an overview of the structure and regulation of the electric power industry. The first section provides information on utility ownership, generation and transmission resources, electricity demand growth, and recent financial trends among private utilities.[1] The second section concludes with a brief introduction to Federal and State regulation of electric utilities, bulk power markets, and transmission access.

A SNAPSHOT OF THE ELECTRIC POWER INDUSTRY TODAY

Industry Ownership and Structure

The electric power industry today is a diverse and heterogeneous amalgamation of investor and publicly owned utilities, government agencies, cogenerators, and independent power producers. The industry consists of more than 3,200 entities that supply electricity to more than 100 million households, commercial establishments, and industrial operations. At present, there are 203 investor-owned utility operating companies, 1,988 local publicly owned systems (including municipal, State, county and regional systems), 994 rural electric cooperatives (including 885 distribution co-ops and 59 generation and transmission co-ops), 59 public joint-action agencies, 6 Federal power agencies, and several hundred cogeneration and small power producers.[2] Table 2-1 shows installed generating capacity and generation by ownership.

Investor-Owned Utilities

The 203 investor-owned utility operating companies dominate the electric power industry, generating 76 percent of the Nation's power and serving about 75 percent of all retail customers.[3] These companies are an assimilation of some 2,000 private utility systems that were in existence in the 1920s. Actual control of the industry is somewhat more centralized because nearly one-quarter of the remaining utility operating companies are subsidiaries of nine registered electric utility holding companies regulated under the Public Utility Holding Company Act of 1935 (PUHCA). The registered utility holding companies are: Allegheny Power System, Inc., American Electric Power Co., Central and South West Corp., Eastern Utilities Associates, General Public Utilities Corp., Middle South Utilities, New England Electric System, Northeast Utilities, and The Southern Company. In addition to the regulated holding companies, there are "exempt" holding company systems consisting of affiliated utility subsidiaries operating intrastate or in contiguous States.

Federal Systems

The Federal Government is primarily a wholesaler of electric power produced at federally owned hydroelectric facilities operated by the Bureau of Reclamation and the U.S. Army Corps of Engineers. Power is marketed through five Federal marketing agencies—Bonneville Power Administration, Western Area Power Administration, Southeastern Power Administration, Southwestern Power Administration, Alaska Power Administration—and through the independent Tennessee Valley Authority, a government corporation. Together, Federal systems had an installed generating capacity of approximately 64,000 megawatts (MW) and accounted for 8.4 percent of the Nation's power generation in 1987.[4] All Federal power systems are required under existing legislation to give preference in the sale of their output to other publicly owned systems and to rural electric cooperatives.

Local Public Systems

In addition to the Federal systems, there are 1,988 local, municipal, State, and regional public power systems ranging in size from tiny municipal distribution companies to giant systems like the Power

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[1] Much of the information in this section is drawn from an OTA contractor report, Scott A. Fenn, "An Overview of the Changing Electric Power Industry," December 1988.

[2] "U.S. Electric Utility Statistics," *Public Power*, January-February 1989, p. 51.

[3] Ibid.

[4] Ibid.

Table 2-1—Electric Utility Industry Installed Generating Capacity and Generation by Ownership, 1987

Type of ownership	Nameplate capacity (MW)	Generation (millions of kWh)
Investor-owned	552,795	2,022,260
Federal	64,666	205,363
Municipal	39,378	86,211
States and power districts	34,858	135,786
Cooperatives	26,359	122,508
Total	718,056	2,572,128

SOURCE: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1987* (Washington, DC: December 1988).

Authority of the State of New York. Publicly owned systems are in operation in every State except Hawaii. Municipal systems are usually run by the local city council or an independent board elected by voters or appointed by city officials. Other public systems are typically run by public utility districts, irrigation districts or special State authorities. Together, local public power systems generated 10.2 percent of the Nation's power in 1987 but accounted for 14.3 percent of total electricity sales, reflecting the fact that many public systems are involved only in retail power distribution.[5]

Rural Electric Cooperatives

Electric cooperatives, an outgrowth of Federal Government efforts to bring electricity to rural areas, now operate in 46 States. Rural co-ops are owned by their members, each of whom has one vote in the election of a board of directors. Congress created the Rural Electrification Administration (REA) in 1935 and subsequently gave it broad lending authority to stimulate rural electricity use. Cooperatives have access to low-cost government-sponsored financing through the REA, the Federal Financing Bank, and the Bank for Cooperatives. Early REA borrowers tended to be small cooperatives that purchased wholesale power for distribution to members. Over the past 20 years, however, many expanded into generating and transmission cooperatives in order to lessen their dependence on outside power sources. In 1987, rural co-ops accounted for 5.2 percent of total power generation and 6.9 percent of sales to ultimate customers.[6]

Industry Power Operations and Coordination

In most areas of the country, utility systems are now highly interconnected and operate under a variety of formal or informal coordination agreements. The level of power transfers and coordination between utilities is determined largely by physical interconnections, power pooling arrangements, and control centers.

Interconnections

North America's interconnected utilities create four physically separate, synchronously operated transmission networks: the Eastern Interconnection (or Seven Council Interconnection); the Texas Interconnection; the Western Systems Coordinating Council (WSCC); and the Hydro Quebec System. The boundaries for these transmission networks are shown in figure 2-1. DC and AC transmission interties between the networks are limited in location and capacity, with the result that the transmission systems in the United States do not form a single national grid, but rather form three separate grids. The transmission barriers between the three grids effectively limit the market areas for electric power in the United States For instance, there is little opportunity for long-distance power transfers between relatively low-cost surplus power areas in the Western Systems network and the higher-cost power systems in the Midwest or between the Texas Interconnection, with its abundance of cogeneration capacity, and utilities in the Southeast. There are sound technical reasons for maintaining the integrity

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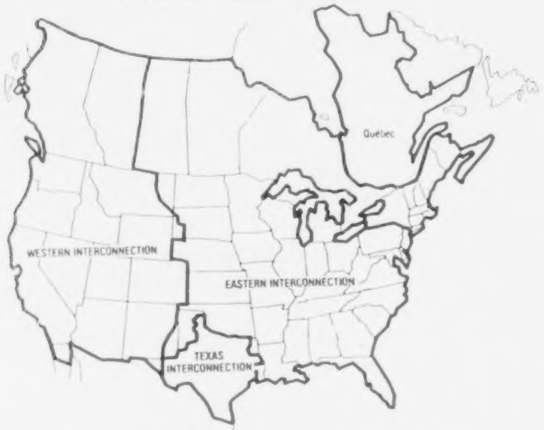
[5] Ibid.

[6] Ibid.

Figure 2-1—Interconnections of the North American Electric Reliability Council



SOURCE: North American Electric Reliability Council, *1987 Reliability Assessment: The Future of Bulk Electric System Reliability in North America, 1987-1996*, September 1987.

of separate synchronous transmission networks. However, it would be possible to construct AC-DC-AC interties to allow greater power flows between these regional networks without disrupting synchronous operations.

Power Pools

There are two types of power pool arrangements—tight power pools, which include holding company power pools, and loose power pools. The nine tight power pools are highly interconnected, centrally dispatched, and have established arrangements for joint planning on a single-system basis. Four of these tight pools consist of utility holding companies with operations in more than one State; the others are mostly multiutility pools. Together, the tight power pools account for about a quarter of the industry's total generating capacity. Figure 2-2 shows the location of the major tight power pools in the United States.

In addition to the tight power pools, there are a number of loose power pools. Arrangements among utilities in loose power pools are quite varied and range from generalized agreements that coordinate generation and transmission planning to accommodate overall needs to more structured arrangements for interchanges, shared reserve capacity, and transmission services.

Existing interutility obligations and economic dispatch and transmission arrangements in interconnected and highly coordinated power pools may tend to limit opportunities for expanded competition in some areas for several reasons. Among the most significant are constraints imposed by existing long-term pooling contracts and the extent of operating economies already captured by pooling. In areas without extensive pooling agreements, increases in power pooling, coordination, and/or power brokering could offer benefits from better utilization of existing capacity that might be similar to those claimed for greater competition in bulk power purchases. One recent study indicates that the savings to consumers resulting from utility coordination and pooling arrangements total in excess of $15 billion annually, and that these annual savings can be expected to increase to more than $20 billion by the mid-1990s.[7]

Control Areas

Responsibility for the operation of the Nation's generating facilities and transmission networks is divided among more than 140 "control areas." In an operational sense, control areas are the smallest units of the interconnected power system. A control area can consist of a single utility, or two or more utilities tied together by contractual arrangements. The key characteristic is that all generating utilities within the control area operate and control their combined resources to meet their loads as if they were one system. If a single control area is used to dispatch the generating facilities of several utilities to minimize overall costs, the process is known as "central dispatch." Because most systems are interconnected with neighboring utilities, each control area must assure that its load matches its own internal generation plus power exports (or interchanges to other control areas) less power imports. Because of interconnection, each control area must satisfy more stringent requirements for generation control, frequency control, and tie line flows than would be needed for an isolated system. Control areas coordi-

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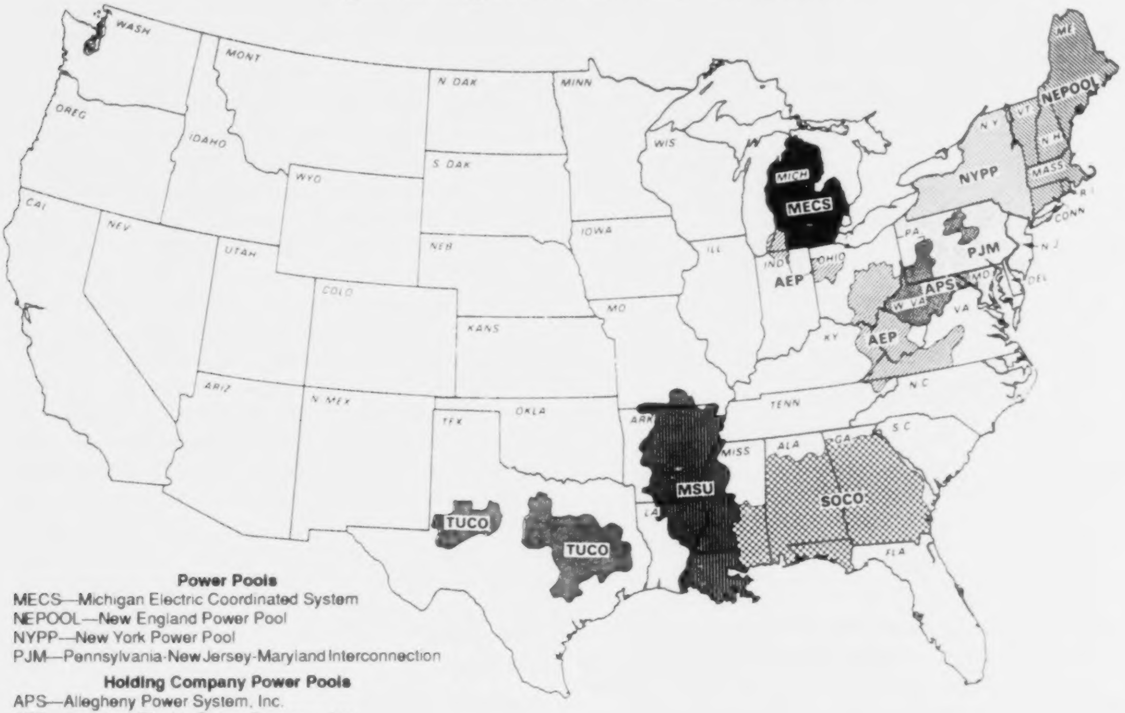
[7] John A. Casazza, "Free Market Electricity: Potential Impacts on Utility Pooling and Coordination," *Public Utilities Fortnightly*, Feb. 18, 1988, pp. 16-23.

Figure 2-2—Tight Power Pools in the United States


WASH
MONT
N DAK
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S DAK
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MECS
NEPOOL
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N H
N Y
NYPP
MASS
R I
CONN
CAL
NEV
UTAH
NEB
IOWA
ILL
IND
OHIO
AEP
PA
PJM
N J
DEL
MD
APS
W VA
VA
COLO
KANS
MO
KY
AEP
ARIZ
N MEX
OKLA
TEX
ARK
TENN
N C
S C
MISS
ALA
GA
MSU
SOCO
LA
TUCO
TUCO
FLA

Power Pools

MECS—Michigan Electric Coordinated System
NEPOOL—New England Power Pool
NYPP—New York Power Pool
PJM—Pennsylvania-New Jersey-Maryland Interconnection

Holding Company Power Pools

APS—Allegheny Power System, Inc.
AEP—American Electric Power Company, Inc.
MSU—Middle South Utilities, Inc.
SOCO—The Southern Company
TUCO—Texas Utilities Company

SOURCE: Federal Energy Regulatory Commission, Office of Electric Power Regulation, *Power Pooling in the United States* (Washington, DC: December 1981).

nate transmission transactions among electric power systems through neighboring control areas. Control areas maintain frequent communications about operating conditions, incremental costs, and transmission line loadings.

There are about 99 control areas in the Eastern Interconnection, about 34 in the Western Interconnected System and 10 in the Texas Interconnected System. Figure 2-3 shows the North American interconnected control areas in 1981.

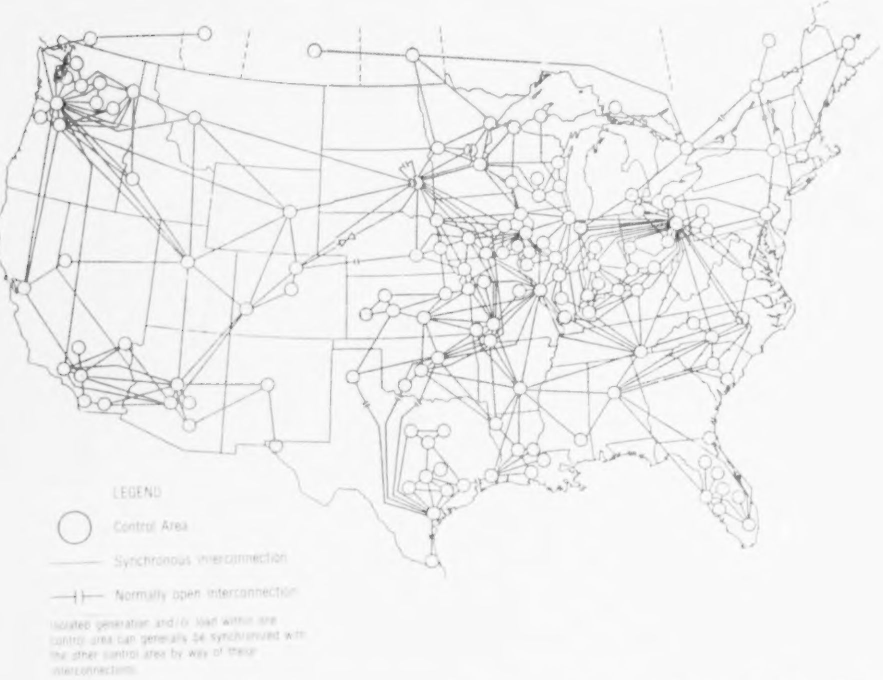
Electricity Generation, Demand and Supply

Major shifts in electric power usage patterns have bedeviled utility planners and energy forecasters since the oil embargoes of the 1970s made previous assumptions about fuel prices, inflation, and economic growth obsolete. Throughout the past decade, the electric utility industry has faced a situation of excess capacity as power plants, ordered in the 1970s, came on line and demand growth fell below the industry's expectations. As it enters the 1990s, however, the industry's problems with excess capacity appear to be receding and, in some regions of the country, capacity margins are tightening to the point that utilities are warning of shortages.

Demand and Peak Growth

Before 1970, electricity demand growth was vigorous and predictable, with power usage growing at an average annual rate of 7.8 percent and peak demand growth averaging 8.1 percent a year be-

Figure 2-3—North American Interconnected Control Areas, 1981


LEGEND
○ Control Area
Synchronous interconnection
—⊣⊢— Normally open interconnection
Isolated generation and/or load within one control area can generally be synchronized with the other control area by way of these interconnections.

SOURCE: Federal Energy Regulatory Commission, Office of Electric Power Regulation, *Power Pooling in the United States* (Washington, DC: December 1981).

tween 1945 and 1970.[8] Utilities underestimated the price elasticity of electricity demand, however, and as consumers reacted to electricity price increases in the 1970s, growth in power demand fell sharply. Since 1973, peak demand growth—the chief determinant of the need for new capacity—and annual kilowatthour (kWh) sales growth have both averaged about 2.5 percent annually.[9] As shown in table 2-2, utility industry expectations of future electricity demand growth—for both peak demand usage and net energy usage—have been reduced in every year during this period and are now below the post-embargo average.

The drop in electricity demand growth is largely a reflection of a stagnation in the average growth of overall energy demand since the early 1970s. Total U.S. energy consumption in 1987 was only slightly higher than it was back in 1973 before the first oil shock, even though the real gross national product rose 39 percent, or about 2.4 percent annually, during this period. Thus, the only source of growth in electricity demand for 15 years has been an increase in electricity's market share relative to other end-use fuels. Electricity has steadily increased its share of the total U.S. energy market from 24.4 percent in 1970 to a record 36.2 percent in 1987 (see figure 2-4).

There are signs that electricity demand growth is beginning to accelerate again in the late 1980s in response to vigorous growth in the economy, including the revival of a number of energy-intensive manufacturing industries and a strong commercial

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[8] Arthur A. Thompson, "The Strategic Dilemma of Electric Utilities—Part I," *Public Utilities Fortnightly*, Mar. 18, 1982, p. 20.

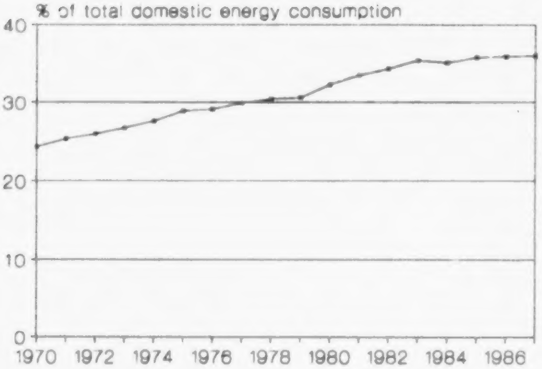
[9] Based on figures from Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1986*. Data exclude Alaska and Hawaii.

Table 2-2—Industry Projections of U.S. Electric Load Growth

Forecast published	Forecast period	Average annual peak demand growth	Average annual net energy growth
1974	1974-83	7.6	7.5
1976	1976-85	6.4	6.3
1978	1978-87	5.2	5.3
1980	1980-89	4.0	4.1
1982	1982-91	3.0	3.3
1984	1984-93	2.5	2.6
1986	1986-95	2.2	2.3
1988	1988-97	1.9	2.0

SOURCE: North American Electric Reliability Council, *Electricity Supply and Demand*, published each year.

Figure 2-4—Electric Power's Energy Market Share, 1970-87



SOURCE: U.S. Department of Energy.

and service sector. Nationwide, summer peak demand growth for the industry reached 3.4 percent in 1986, 4.2 percent in 1987, and 6.1 percent in 1988, while total electricity kWh sales rose 2.1 percent in 1986, 3.7 percent in 1987, and an estimated 4.6 percent in 1988.[10]

Growth in electricity demand in recent years is rekindling debate over whether utilities are building sufficient capacity to meet future demand and how they should meet this demand. A number of analysts contend that the industry is now underestimating future demand growth in the same way that it overestimated such growth over the past decade. Other analysts, however, contend that customer responses to higher electricity prices—including efficiency investments, relocation of production facilities outside the United States, and onsite power production—will continue to moderate future demand for utility-produced power.

Generating Capacity

Total installed electric utility generating capacity reached 718,056 MW in 1987, an increase of 1.5 percent over 1986, with investor-owned utilities accounting for 77 percent of this capacity.[11] The distribution of this installed nameplate capacity by type of ownership is shown in table 2-1. In addition to this utility-owned capacity, it is estimated that nonutility companies had installed approximately 25,000 MW of cogeneration and small power capacity through 1987.[12]

Fuel Mix

Coal is the dominant source of U.S. electric generation, providing 56.9 percent of all electricity generated in 1987, as shown in figure 2-5. Nuclear power provided 17.7 percent, hydroelectric facilities provided 9.7 percent, natural gas accounted for 10.6 percent, fuel oil provided 4.6 percent, and other sources—including geothermal, wood, waste, wind and solar—accounted for the remaining 0.5 percent.[13]

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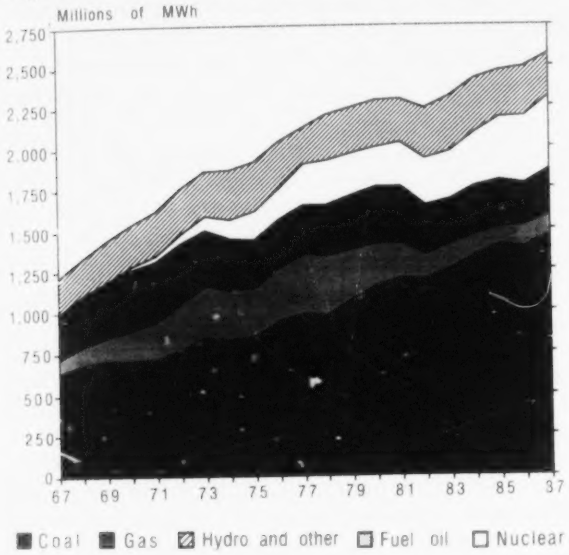
[10] Carl Tobie, personal communication, Edison Electric Institute, Feb. 13, 1989.

[11] Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1987* (Washington, DC: December 1988), p. 6.

[12] "EEI: Over 25,000 MW of Non-utility Capacity Was in Service As of 1986," *Electric Utility Week*, Aug. 5, 1988, p. 13; and "Profile of Cogeneration and Small Power Generation Markets—1988 Edition," *Energy User News*, May 23, 1988, p. 2.

[13] Edison Electric Institute, supra note 11, p. 32.

Figure 2-5—Electric Power Generation by Fuel Source



SOURCE: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1987* (Washington, DC: December 1988).

Capacity and Reserve Margins

To meet expected load growth and to preserve system reliability, utilities maintain generating capacity reserves. Reserve margins express the difference between demonstrated capacity and peak demand as a percent of total peak. The traditional industry target has been to maintain a 20 percent reserve margin, although individual utilities have adopted different targets depending on many factors, including individual plant characteristics (e.g., age, size, type), access to power from other systems, and characteristics of customer demand. Actual electric utility industry reserve margins increased from around 20 percent in the early 1970s to 30 percent in the late 1970s and reached 35 percent in the mid-1980s before beginning to decline—although there are significant differences in reserve margins on a regional basis as discussed in chapter 6. Trends in annual industry capability, summer peak loads, and adjusted capacity margins are shown in table 2-3.

Transmission Capacity

Transmission systems have been utilized in the past for the delivery of both capacity and energy. Under the first function, the seller provides a fixed amount of capacity and associated energy to the buyer for a specified time. Because the provision of this capacity is contractually guaranteed, the purchasing utility can include it in its reserve margin and use it as a substitute for additional generating capacity. In contrast, when energy alone is sold, the seller provides a given amount of energy over a specified period of time, but the availability of energy at any instant is not assured. This type of arrangement enables the purchasing utility to reduce its costs by substituting less expensive purchased power for more expensive electricity from its own generating stations, but it does not reduce the amount of generating capacity needed by the purchaser to meet reserve requirements.

In recent years, because of high industry reserve margins, transmission systems have been used more for providing energy to reduce fuel costs than for providing capacity to avoid construction of new generating facilities. As industry reserve margins fall, however, the capacity function of transmission systems is expected to become more significant.[14] The pace of new transmission line additions has been declining in recent years. As of year-end 1987, the U.S. transmission system consisted of about 616,400 circuit miles of transmission lines of 22 kilovolts (kV) and above.[15] Approximately 79 percent of these circuit miles were owned by investor-owned utilities.

Bulk Power Sales and Wheeling

Bulk power sales are defined as the sales of electricity at wholesale for resale or transmission of power for other systems (wheeling service). Such transactions constitute a significant share of total electricity sales in the United States.[16] Wholesale power sales are generally divided into two categories: requirements sales, in which typically a vertically integrated, investor-owned utility sells power to meet the demand of a publicly owned utility that

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[14] See John A. Casazza, "Free Market Electricity: Potential Impacts on Utility Pooling and Coordination," *Public Utilities Fortnightly*, Feb. 18, 1988, p. 16.

[15] Edison Electric Institute, supra note 11, p. 97.

[16] Linda Martinson and Thomas Loria, "The Transitional Bulk Power Market," *Public Utilities Fortnightly*, Nov. 26, 1987, p. 19.

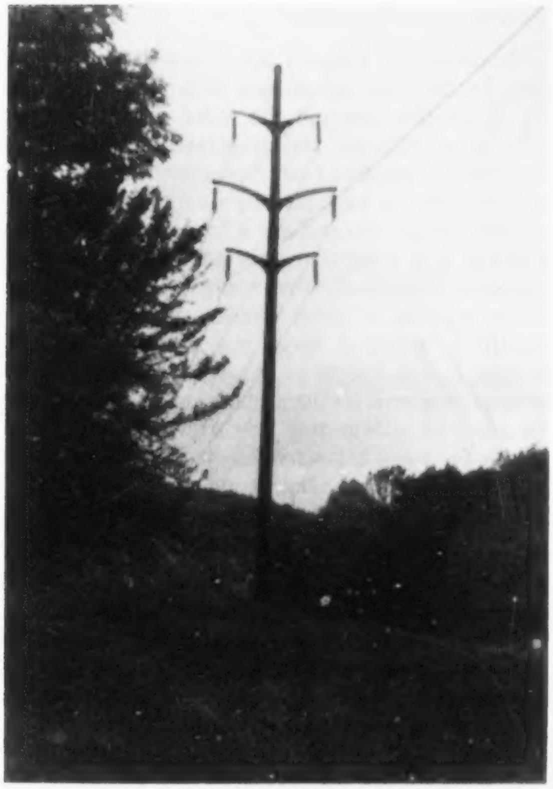

Photo credit: Casazza, Schultz & Associates, Inc.

A modern high voltage tower

owns little or no generating capacity; and coordination sales, typically involving two vertically integrated, investor-owned utilities.

Meanwhile, wheeling transactions, involving the transmission of power between two utility systems on a prearranged basis over the lines of one or more other systems, have become routine in the industry. Wheeling transactions are arranged on a voluntary basis and are generally subject to approval by the Federal Energy Regulatory Commission (FERC), where there are currently about 1,400 such agreements on file. Cost disparities and the development of sophisticated communications and control technologies have fostered an increasingly active market in bulk power transfers between utilities. Canadian power imports are also increasing. (See box 2-A on recent trends in bulk power purchases from Canada.) There are pressures from some sectors of the power industry to expand the number and the size of these transactions and to make them a more integral part of electric system planning. Independent power producers and cogenerators, in particular, see greater access to transmission facilities as essential to their future growth.

Electricity Prices

Prices for electricity, like virtually all energy supplies, rose substantially in the 1970s and early 1980s in response to higher oil prices and general inflationary pressures in the economy. Unlike fossil fuel prices, however, which have retraced much of their earlier upward climb in recent years due to an excess of world oil production over demand, electricity prices have moderated only slightly. In large measure, this is due to the impact of a generation of very expensive generating plants, particularly nuclear units, that entered service during the 1980s. In addition, the fact that electricity prices are regulated

Table 2-3—Total Electric Utility Industry Capability, Peak Loads, and Capacity Margins (excluding Alaska and Hawaii)

Year	Capability at time of summer peak load	Noncoincident summer peak load	Capacity margin at noncoincident peak
1978	545.7	408.1	25.2
1979	544.5	398.4	26.8
1980	558.2	427.1	23.5
1981	572.2	429.3	25.0
1982	586.1	415.6	29.1
1983	596.4	447.5	25.0
1984	604.2	451.2	25.3
1985	621.6	460.5	25.9
1986	633.3	476.3	24.7
1987[a]	647.9	496.2	23.4

[a] Preliminary

SOURCE: Edison Electric Institute, *Annual Report of the Investor Owned Electric Utility Industry, 1987 Financial Review*

Box 2-A—Electric Power Imports From Canada

As economic, political, and environmental problems have led to a slowing of new power plant construction in the United States, a number of U.S. utilities have begun to turn to Canadian imports as an attractive option for meeting future demand. Since the early 1970s, U.S. utilities have steadily increased the amount of power purchased from Canada—from less than 10 billion kWh in 1970 to an estimated 42 billion kWh in 1987—with roughly three-quarters of these imports displacing imported oil. The U.S. Department of Energy estimates that since the 1973 oil embargo, Canadian power imports have resulted in savings of more than $7 billion for U.S. consumers compared to the cost of imported oil.

While still accounting for less than 2 percent of total U.S. electricity demand, Canadian imports are significant in certain regions. In the State of New York, for instance, Canadian imports have accounted for about 12 to 17 percent of total power supplies in recent years. In addition, electricity imports from Canada are poised for further growth.

There is widespread agreement among utility industry experts that Canadian power imports will continue to grow, although there are substantial differences of opinion about the extent of this growth. Most estimates predict that import levels could range from 52 to 66 billion kWh annually by 1995. Among the factors that are leading to growth in imports are:[1]

- **Canadian energy reserves**: Canada has enormous untapped energy reserves, including economically attractive undeveloped hydroelectric reserves in northern Canada capable of supplying as much as 60,000 MW of generating capacity for which there is currently no Canadian market.
- **Ease of power plant construction**: In general, power plant construction appears to be somewhat less onerous in Canada than in the United States. Construction delays, cost overruns, and prudence reviews by regulators have made U.S. utilities extremely cautious about new plant construction.
- **Canada's economy and industry structure**: General economic conditions in some Canadian provinces, along with the government-owned structure of the Canadian provincial utilities, are making the construction of power plants for the export market increasingly attractive. Three provincial utilities are considering accelerating the construction of hydroelectric facilities for the U.S. export market. British Columbia has also formed a provincially owned corporation to sell privately produced power exclusively to export markets in the Western United States.
- **The U.S.-Canada Free Trade Agreement**: The recently negotiated U.S.-Canada Free Trade Agreement is expected to enhance the prospects for future electricity trade by increasing the security of Canadian energy supplies and lowering the cost of imports through the elimination of a discriminatory price test.

As Canadian imports grow, the arrangements under which power is being sold to U.S. utilities are also changing. To date, most Canadian imports—72 percent in 1986—have been interruptible economy transactions. Power sales are now shifting from short-term interruptible sales to firm, longer term contracts for energy and capacity. In 1987 alone, U.S. and Canadian utilities signed three major multi-billion dollar, multiyear power import deals. As a result, U.S. utilities are increasingly able to use Canadian electricity imports to defer or cancel new domestic power plant construction.

The most important limitation on future growth of Canadian imports is likely to be a shortage of transmission capacity. At present, more than 30 high-voltage transmission lines cross the border between the United States and Canada, with a carrying capacity of more than 10,000 MW. Each region along the northern tier of the United States has at least several lines. Most of these lines already operate near full capacity, however; so plans to expand U.S.-Canadian electricity trade further will require construction of additional transmission capacity. The New England Power Pool, for instance, is building a $570 million, 130-mile transmission line from the endpoint of its existing interconnection with Hydro-Quebec in New Hampshire to Massachusetts in order to begin importing an additional 7 billion kWh annually from Canada. Acquiring right-of-way for new transmission lines is difficult though, and a recent wave of public concern about the possible health effects associated with transmission lines is likely to intensify opposition to new lines.

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[1] See Dina Washburn Kruger, *Plugging Into Canada: Prospects for U.S.-Canadian Electricity Trade* (Washington, DC: Investor Responsibility Research Center, 1988).

Continued on next page

Continued from previous page

Moreover, technical, economic, and environmental concerns in the United States and Canada may limit further expansion of electricity trade. Some U.S. utilities are concerned about the reliability of Canadian supplies, particularly in light of weather-related curtailments by Hydro-Quebec in January and April 1988. Others are opposed to imports because of the pricing structure used by Canadian utilities, which ties import prices to the importing utility's cost of displaced generation. Finally, many Canadians remain opposed to exploiting Canada's untapped energy resources for the U.S. market and a growing environmental movement within Canada could constrain the development of new hydroelectric dams.

These concerns notwithstanding, it appears that over the near term, the powerful forces driving import growth will overshadow import opponents. Over the longer term, it is also possible that emerging environmental concerns, such as global warming caused by the burning of fossil fuels, will give new impetus to the development of noncombustion technologies such as Canada's hydro resources.

The likely beneficiaries of growing cross-border electricity trade include U.S. consumers, utilities that can limit their construction programs or that control strategic transmission corridors, and financial institutions that participate in financing major Canadian construction projects. Opportunities may also arise for U.S. utilities or independent power producers to participate in Canadian power development through joint ventures with Canadian utilities. Among those firms that could be adversely impacted by Canadian imports are utilities and independent power producers attempting to sell excess capacity in the bulk power markets, nuclear and coal plant vendors, and domestic coal mining companies. Perhaps most importantly, the growth of power imports from Canada is further evidence of the competitive conditions emerging in domestic bulk power markets.

has tended to make them adjust more slowly than those of primary fuels to underlying economic trends. Consequently, the price gap between electricity and primary fuels has widened somewhat since 1980, as can be seen in figure 2-6. As consumers react to these new relative prices, it is likely that utilities can expect greater interfuel competition in the coming decade.

As figure 2-7 shows, electricity prices have risen substantially over the past two decades. The average revenue per kWh sold by the utility industry rose from about 1.5 cents per kWh in 1970 to about 6.5 cents per kWh in 1986, in current dollars. Electricity prices for residential and commercial customers during this period were, on average, about 50 percent higher than those for industrial customers, although price trends for all three major customer classes have followed very similar patterns.

TRENDS IN INDUSTRY INVESTMENTS, BUSINESS STRATEGIES, AND STRUCTURE

Projected Industry Capacity Additions

The generating capability of the of the U.S. electric utility industry is estimated to have reached 718,056 MW as of year-end 1987.[17] Projections of future electric generation capacity additions are fraught with uncertainty because of ongoing changes in industry structure and regulation. In recent years, few utilities have been willing to commit to construction of new base-load capacity, in spite of the continued aging of the existing generating plant stock and predictions from some industry and government planners that the country faces possible shortages in the early to mid-1990s. Meanwhile, the flow of new plant additions by utilities entering service as a result of orders placed in the 1970s is

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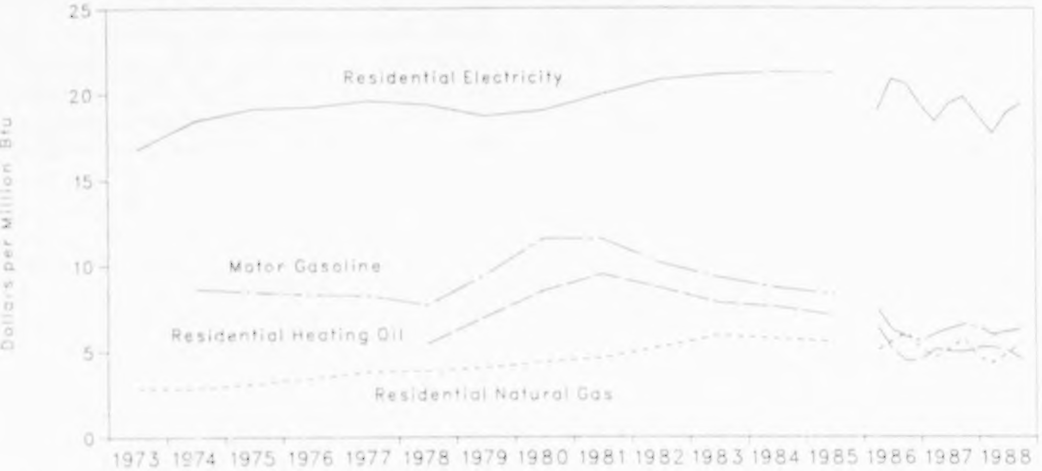
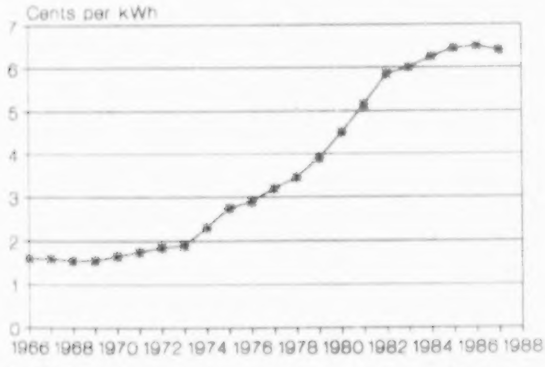
[17] Edison Electric Institute, supra note 11.

Figure 2-6—Cost of Fuels to End Users in Constant Dollars (1982 dollars)



SOURCE: Energy Information Administration, *Monthly Energy Review, October 1988* (Washington, DC: Jan. 26, 1989).

Figure 2-7—Average Utility Revenues Per Kilowatthour Sold, 1966-87



SOURCE: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry 1987* (Washington, DC: December 1988).

slowing to a trickle, although capacity additions by nonutility generators are increasing.

In 1988, only two utility-owned, coal-fired generating units are expected to come on line—marking a record low for the last two decades—and by 1992 only 13 utility-owned coal units totaling 8,383 MW of capacity are due to enter service. Nationwide, utilities are projected to add only 29,700 MW of capacity from all sources during this period.[18] Through 1997, utilities and nonutility generators are projected to bring on line about 73,440 MW of capacity additions, with nuclear units accounting for about one-fourth of this total as shown in table 2-4.[19]

Capital Spending Patterns

The U.S. electric utility industry is expected to spend approximately $27 billion for new facilities in 1988, according to recent industry surveys.[20] Industry capital expenditures have been falling in recent years since peaking in 1982 at more than $40 billion (see figure 2-8). Annual utility industry capital spending has already fallen by about one-third (in constant dollar terms) since 1982.

Capital spending in the electric power industry is expected to continue to fall for at least several more years before beginning to rise again sometime in the 1990s. Industry capital spending is projected to fall

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[18] "Coal-Fired Power Plant Construction Hits All-Time Low, UDI Report Says," *The Energy Report*, July 18, 1988, p. 494.

[19] North American Electric Reliability Council, *1988 Electricity Supply and Demand for 1988-1997*, October 1988, p. 48.

[20] "1988 Annual Statistical Report," *Electrical World*, April 1988, p. 51 (estimates $26.6 billion); Edison Electric Institute, *EEI Financial Info*, May 25, 1988 (estimates $25.3 billion for investor-owned utilities); and *Electric Light & Power*, January 1988 (estimates $27.5 billion).

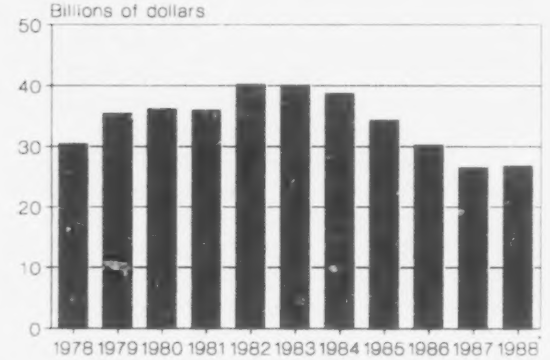
Table 2-4—Generating Unit Additions, 1988-97

Type	Thousands of megawatts	Percent of total
Nuclear	18.2	24.8
Coal	15.4	21.0
Hydro	1.7	2.3
Oil/gas	13.6	18.5
Pumped storage	2.1	2.9
Other (utility)	2.6	3.5
Nonutility	19.8	27.0
Total additions	73.4	100.0

NOTE: Figures are rounded.

SOURCE: North American Electric Reliability Council, *1988 Electricity Supply and Demand for 1988-1997*, October 1988, p. 49.

Figure 2-8—Electric Utility Capital Expenditures



*Estimated

SOURCE: Electrical World surveys.

steadily through 1992, reaching a level of $22.2 billion, as shown in table 2-5.

The drop in industry capital spending is the result of a sharp decline in spending for new generating capacity. Capital spending for utility transmission and distribution projects has actually been rising in recent years, although the amounts are small in comparison to the decline in spending for new generation projects. The changing composition of the industry's future spending is illustrated in table 2-6, which shows different categories of forecasted capital spending by electric utilities. It is interesting to note that the 1990 forecast period is the first period where transmission and distribution spending is expected to exceed spending on new generation facilities. This change underlines the growing importance of off-system power sales, wheeling, and retail marketing to many utilities' strategic planning.

Growth in Nonutility Generation

The slowing of utility construction of new generating capacity is, to some extent, being offset by continuing growth in cogeneration and power production facilities built by nonutility entities and by unregulated utility subsidiaries. Since the passage of The Public Utility Regulatory Policies Act (PURPA) in 1978, the amount of electricity received by utilities from nonutility sources has grown dramatically. Estimates of current and projected nonutility capacity vary considerably, however, so it is difficult to measure the growth of this industry with precision. One measure of this growth can be traced through the marked increase in the number and size of filings submitted to FERC, which is charged with administering PURPA and certifying "qualifying facilities" (QFs) under the law. While these filings are not a precise indicator of the growth of nonutility power production—because a substantial number of projects filed with FERC are never brought to fruition—the growth in these filings, from 29 projects totaling 704 MW in fiscal 1980 to a cumulative total of 3,717 projects totaling 61,950

Table 2-5—Electric Utility Projected 5-Year Capital Expenditures by Function (millions of dollars)

Function	1988	1989	1990	1991	1992	5-year total
Generation	12,296	10,769	9,443	8,199	8,385	49,092
Substations	1,371	1,384	1,225	1,360	1,175	6,515
Transmission	2,558	2,376	2,397	2,795	3,092	13,218
Distribution	7,979	7,010	7,929	7,882	6,965	37,765
Other	3,281	3,106	3,118	3,054	2,622	15,181
Total	27,485	24,645	24,112	23,290	22,239	121,771

SOURCE: "Electric Utilities Will Increase Spending Plans Through 1992," *Electric Light & Power*, January 1988, p. 12.

Table 2-6—Changing Patterns of Utility Capital Investment, 1988-92

Function	1988	1989	1990	1991	1992
Generation	44.7%	43.7%	39.2%	35.2%	37.7%
Transmission and distribution	43.4	43.7	47.9	51.7	50.5
Other	11.9	12.6	12.9	13.1	11.8
Total	100.0	100.0	100.0	100.0	100.0

SOURCE: "Electric Utilities Will Increase Spending Plans Through 1992," *Electric Light & Power*, January 1988, p. 11.

MW by the end of 1987, do serve to illustrate the surge in nonutility generation.[21]

Although there is no definitive count of nonutility capacity actually on line, a recent survey by the Edison Electric Institute found 25,321 MW of nonutility capacity in operation at the end of 1986 from 2,449 projects. Of this total, 1,647 projects totaling 16,097 MW were qualifying facilities under PURPA. Cogeneration facilities accounted for 18,448 MW, or about 73 percent, of the total. Small power production capacity provided 20 percent, while other nonutility producers accounted for 8 percent. Three quarters—18,968 MW—of the total nonutility capacity was interconnected to utility systems. A second small power database lists 1,808 QF projects, representing 24,833 MW of capacity, as operational through 1987.[22] Meanwhile, estimates of future capacity growth vary widely. Several estimates suggest that roughly 38,000 MW of nonutility capacity will be on line and selling power to utilities by 1995.[23] By the year 2000, some studies estimate that nonutility capacity will range from 40,000 to 80,000 MW.

Changes in Company Business Strategies

A number of important trends in the utility industry operating and regulatory environment have led many utilities to undertake fundamental reassessments of their corporate strategies in the 1980s. In general, utilities have begun to function more like competitive, market-driven businesses in response to an increasingly competitive and less regulated operating environm[illegible]t. The new, more competitive operating environ[illegible] is the result of a variety of factors, including dissatisfaction with the results of traditional rate-of-return regulation, greater interfuel competition, changes in the industry's cost structure, and technological developments. (Some of the implications of a more competitive industry are shown in figure 2-9.) In the process of adapting to this new environment, the utility industry has shifted from a very homogeneous one—in which virtually all individual companies were pursuing the same strategy, namely to build new generating capacity to satisfy growing customer demand—to one in which companies are pursuing distinctly different business

Figure 2-9—Implications of Competition for Electric Utilities

Noncompetitive environment:
- Cost-based pricing
- Supply-oriented
- Regulatory allocation of cost across customer classes
- Obligation to serve all customers
- Service reliability a part of the obligation to serve
- Construction costs included in rate base
- Integrated services from power plant to customer meter
- Resources based on needs of service area
- Cost centers managing to budget

Competitive environment:
- Market-based, more flexible pricing
- Demand-oriented
- Cost management systems allocate cost by market segments
- Ability to "cherry pick" customers
- Reliability negotiated based on customer need
- Construction costs at risk
- Pressure to separate generation, transmission, and distribution services
- Resources allocated based on profitability
- Profit centers managing performance

SOURCE: Electric Power Research Institute, *Competition: Pressures for Change* (Washington, DC: June 1967).

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[21] "EEI: Over 25,000 MW of Non-Utility Capacity Was in Service As of 1986," *Electric Utility Week*, Aug. 5, 1988, p. 13.

[22] *Energy Users News*, supra note 12, p. 1.

[23] See Douglas Cogan and Susan Williams, *Generating Energy Alternatives—1987 Edition* (Washington, DC: Investor Responsibility Research Center, May 1987); and RCG Hagler, Bailly, Inc., supra note 12.

strategies. These strategies can be summarized as follows:[24]

Modified Grow and Build

A number of utilities have continued to view the completion of large nuclear and coal plants, initiated in the 1970s, as their best option. This strategy is largely a continuation of that used by virtually the entire industry since its beginning. In the new utility environment, however, it typically includes increased emphasis on marketing to both retail and wholesale customers. Some utilities are also emphasizing growth through mergers or the acquisition of other utilities.

Capital Minimization

Many utilities are continuing to react to both overbuilding in the industry and regulatory uncertainty with a strategy of minimizing capital expenditures in order to minimize financial and corporate risk. Elements of this strategy include canceling plants both planned and under construction, increasing use of purchased power, participating in joint ventures if construction is necessary, selling excess capacity, rehabilitating existing plant, and devoting increased attention to energy efficiency and load-management programs.

Diversification

A majority of investor-owned utilities have begun to diversify their business interests by investing revenues in potentially more profitable business ventures outside the electric utility business. Salomon Brothers Inc., for instance, found that 58 of the 100 utilities it follows have diversified or indicated an intention to diversify, including 24 that have formed holding companies during the past 5 years.[25] While the level of these expenditures is still relatively small for most utilities, a number of utilities now have sizable nonutility interests and the overall level of diversification activities in the industry is continuing to increase at a rapid pace. Pacificorp, one of the most diversified major electric utilities, obtained nearly half of its total revenues in 1987 from operations outside of the electric utility business, including coal, gold and silver mining, regulated and unregulated telecommunications businesses, and financial services.

Nontraditional Energy Technologies

Some utilities have embarked on a strategy of significantly increasing reliance on alternative energy sources (including cogeneration, renewable energy sources, and other power supplies from nonutility sources) in an effort to reduce construction lead times and other risks from traditional power plant construction, mitigate public concerns about the environmental impacts of power generation, and shift supply risks to outside entities. Many more utilities have initiated increased research and development programs in new technologies, but they are adopting a "wait and see" attitude about major commitments to these sources.

Outlook

At present, the utility operating environment remains quite uncertain, so it is common to find utilities pursuing more than one of these strategies simultaneously. There is a considerable amount of strategic positioning and experimentation taking place, but only a few utilities seem confident to make major strategic bets about the future direction of the industry. Most utilities seem to be attempting to hedge their risks by adopting measures to limit capital expenditures on the utility side of the business while attempting to gain experience with diversification into nonutility businesses. As market forces continue to exert a greater influence over the bulk power industry, utilities will be pressured to more clearly define and implement their strategic plans, and competition and rivalry between utilities are likely to continue to grow.

Industry Restructuring Trends

As one means of implementing their new business strategies, utilities are beginning to adopt a variety of financial restructuring measures designed to improve their operational and financial flexibility. Among the most significant types of financial restructuring evolving are sale-leaseback transactions, joint venture agreements with nonutility companies, vertical disintegration, negotiated mergers, leveraged buyouts, and hostile takeovers.[26]

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[24] For further discussion of these strategies and utility implementation of them, see Scott A. Fenn, *America's Electric Utilities: Under Siege and in Transition* (New York, NY: Praeger, 1984).

[25] Mark Luftig et al., "Electric Utility Diversification," Salomon Brothers, Inc., October 1988.

Sale-Leaseback Arrangements

One of the most common forms of restructuring that utilities are using is sale-leaseback transactions as an alternative to traditional finance methods. Utilities have used such transactions in the past for small facilities. Recently, however, they have begun utilizing lease financing in the funding or refunding of major assets. These transactions generally involve utilities selling generating plants or power lines to institutional investors and agreeing to lease back these facilities under a long-term contract, typically at very attractive rates relative to existing debt. In 1987, for example, Kansas Gas & Electric Co. arranged the sale and leaseback of the La Cygne 2 coal plant with U.S. West Financial Services for $400 million. Since the beginning of 1986, 11 power plants, including 4 nuclear plants, have been sold or put up for sale under sale-leaseback arrangements.[27]

Joint Venture Agreements

Another restructuring strategy being adopted by some utilities is the use of joint venture agreements with nonutility companies. Utilities have long been involved in joint venture arrangements among themselves to construct major generating facilities and transmission lines. In recent years, however, some utilities have begun pursuing joint ventures with nonutility entities as a way to recapitalize certain assets or to enter new businesses. Perhaps the best examples of utilities using joint ventures to enter new business areas are the joint ventures emerging between utilities and nonutility power producers in the area of cogeneration and independent power projects. In April 1987, for example, Dominion Resources Inc., the holding company for Virginia Power, announced that it was forming a joint venture with a subsidiary of CSX Corp. to develop coal- and gas-fired cogeneration projects in New England and the Middle Atlantic States. In the past 2 years, at least 10 such joint venture arrangements have been announced, suggesting that utilities see such ventures as an important way to participate in the evolving market for unregulated generating projects.

Vertical Disaggregation

Vertical disaggregation, or the "unbundling" of utility companies based on the functions that they perform, is another concept that a number of utilities are actively considering or pursuing. Basically, this involves the separation of all or portions of a utility's generation, transmission, and distribution functions into two or more entities that are owned and operated independently of each other. The British Government has also expressed an interest in "unbundling" utility functions to promote competition. Information on the British proposal is presented in box 2-B.

Utilities are exploring vertical disaggregation for various reasons, including:

- fears of disallowances by State regulators for imprudent costs for new power plants entering service,
- a desire to attain greater flexibility in future pricing (because many disintegration proposals would allow utilities to fall under Federal jurisdiction over wholesale power sales), and
- as a way for the securities markets to differentiate the individual risk characteristics of the various components of the electric power business.

State regulators have expressed considerable opposition to the major vertical disaggregation proposals that have been made to date, which include a proposal by Commonwealth Edison Co. to put three of its nearly finished nuclear plants into a separate but wholly owned generating company subsidiary that would sell power back to the utility and a proposal by Public Service Co. of New Mexico to separate its operations into independent generation and distribution companies. It should be noted that the Commonwealth Edison Co. proposal has been defeated and the Public Service Co. of New Mexico proposal withdrawn.

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[26] For a detailed discussion of utility restructuring activities, see Scott A. Fenn, "Competition and the Role of the Capital Markets in Restructuring the Electric Power Industry," OTA working paper, December 1987; and Scott A. Fenn, *Mergers and Financial Restructuring in the Electric Power Industry* (Washington, DC: Investor Responsibility Research Center, May 1988).

[27] Both investor-owned utilities and electric cooperatives have used sale-leaseback arrangements.

Box 2-B—Creating a Competitive Generation Industry in Great Britain

In February 1988, Britain's Department of Energy proposed to privatize its electric utilities in England and Wales. The proposal is aimed at promoting competition by eliminating the industry's monopoly on generation.

Current Industry Structure

The Central Electricity Generating Board (CEGB) produces almost all (95 percent) of the power used in England and Wales today. It also owns and operates the transmission grid, which includes interconnections with Scotland and France. The CEGB plans capacity additions, specifies plant design and performance requirements, and supervises construction. The CEGB sells its power to 12 nationalized distribution entities, called area boards, which distribute the electricity to customers. According to the government, the CEGB is "an effective monopoly in areas where this is unnecessary and harmful to the interests of customers."[1]

Proposed Changes

The government's proposal separates generation from transmission and distribution. The CEGB will be divided into two competing generation companies and an independent national grid company. The two generating companies—National Power and Power-Generation—will own 70 percent and 30 percent of existing plants respectively. The 12 area boards will be privatized as licensed distribution companies that can purchase power from a number of sources, including the two newly created generation companies, private generators, or foreign suppliers. Distributors also may construct their own generating units or enter into joint ventures to produce electricity. The area distributors will jointly own and control the new National Grid Company. The National Grid Company will be responsible for coordinating power plant operation and for acquiring new capacity through competitive bidding.[2]

Contracts will provide the basis for business relationships among generators, distributors, and the grid company. The distributing companies can contract for power supplies with the generators directly or through the grid company. In both cases, the Grid Company would have to be involved in order to ensure the reliability of the entire system. The national government will regulate prices in the retail market but not in the wholesale market. Adjacent regional distributors will be free to compete for large customers.[3]

Furthermore, the government proposal specifies that generation, transmission, and distribution companies be licensed by the Energy Department. The four kinds of licenses proposed cover: 1) companies that control low-voltage distribution lines, 2) companies that have more than 50 MW generation capacity and sell to the wholesale market, 3) companies that sell to a specific user or situation, and 4) the National Grid Company.[4]

R&D facilities will be divided among the three new companies. These labs will conduct research for all three new companies until the official split in the early 1990s. After that, companies will conduct their own independent research, although some research may continue to be jointly funded.[5]

The Department of Energy is seeking approval for its proposal (in the form of a "Royal Assent") by summer 1989.

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[1] *Privatising Electricity—The Government's Proposals for the Privatisation of the Electricity Supply Industry in England and Wales*, presented to Parliament by the Secretary of State for Energy by Command of Her Majesty, February 1988.

[2] Ibid.

[3] Ibid.

[4] "Fair Play: British Define Terms of New Licenses for Generating Companies," *Energy Daily*, Dec. 8, 1988, p. 3.

[5] "British Tackle Tricky Task of Dividing Electricity R&D After Privatization," *Energy Daily*, Nov. 18, 1988, p. 1.

Negotiated Mergers, Acquisitions, and Leveraged Buyouts

Negotiated or "friendly," mergers between utilities are likely to be one of the most significant types of utility restructuring activity. For example, a merger between the Pacificorp and Utah Power & Light Co. has recently been completed and a proposal by SCEcorp. to merge with San Diego Gas & Electric Co. is being pursued by the companies but is experiencing opposition. Hostile takeovers and acquisitions are likely to be difficult in the utility industry because of regulatory concerns, but it appears possible that some hostile transactions will succeed, particularly in cases where the strictures of the Public Utility Holding Company Act of 1935 are not invoked. Leveraged buyouts (LBO), in which a small group of investors buy out a company's public shareholders at a premium, usually using the target company's asset base or cash flow to support a highly leveraged capital structure, have not been a factor in the electric power industry to date, although there have been at least two attempts to take a utility private in an LBO-type transaction.

Although actual merger and acquisition activity has not lived up to many people's expectations, the pace of such activity has clearly begun to quicken, with about 10 merger or acquisition proposals announced in the last 3 years.[28]

Public and Private Power Takeover Battles

Another type of restructuring activity underway involves attempts by city or State governments to gain control of investor-owned utilities, and attempts by investor-owned utilities to gain control of publicly owned utilities. The catalyst for a number of these takeover situations of the first type appears to be the prospect for dramatic rate increases related to nuclear plant construction or operation. A number of city governments are looking at the option of creating municipal utilities to take over investor-owned electric distribution systems, although this option was made considerably less attractive by the passage of tax legislation late in 1987 that largely precludes State and local governments from using tax-exempt financing to acquire private electric utility assets. Among the large cities studying the municipal takeover option are Chicago, New Orleans, and Albuquerque. There also appears to be considerable interest, however, in what are essentially buyouts of municipally owned and cooperative electric systems by the investor-owned sector.

Measures of Financial Health

Declines in utility industry capital spending have had a favorable impact on the industry's overall financial performance and health in recent years. In fact, by some measures, the industry's financial position is now stronger than it has been since the industry's "golden age" of the 1950s. Among the indicators commonly used to monitor the industry's financial health are internal cash generation, capitalization ratios, bond ratings, and trends in returns on equity and rate decisions.

Internal Cash Generation

The decline in industry capital spending is particularly significant because it is occurring at a time when the power industry's internal cash generation capability is climbing—meaning that less and less of the industry's capital spending needs to be externally financed.

As shown in figure 2-10, Salomon Brothers Inc. predicts that the utility industry will finance 77 percent of its construction expenditures from internal funds in 1988, 85 percent in 1989, and 95.5 percent in 1990—up from only about 33 percent in 1980. In addition, Salomon Brothers estimates that by 1990, 40 percent of all electric utilities it monitors will be generating 100 percent of the capital they need for construction from internal funds.[29]

Capitalization Ratio

The improvement in the industry's financial position in recent years can also be seen in the industry's capitalization ratios. As shown in table 2-7, the percentage of common equity in the industry's capital structure is now at its highest level in more than 20 years, and is continuing to improve. In fact by this measure, the industry's financial position is now the strongest it has been since the 1940s.

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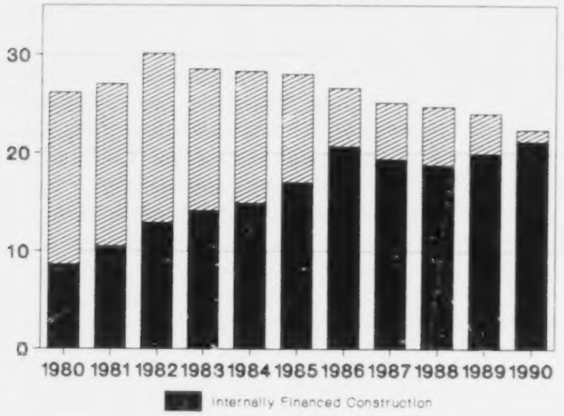
[28] Among the utilities involved in merger and acquisition activities in recent years are Cleveland Electric Illuminating Co. and Toledo Edison Co. (merger announced in June 1985); Public Service Co. of Indiana (informal LBO bid by outside investment group in October 1986 was spurned by management); Newport Electric Co. (hostile tender offers in 1986 and 1987 resulting in new ownership); Pacificorp and Utah Power & Light Co. (merger announced in August 1987 and approved by FERC in October 1988); Pacific Gas & Electric Co. (proposal to buy Sacramento Municipal Utility District made in September 1987 and later dropped); The Southern Co. (agreed to acquire Savannah Electric & Power in October 1987); Public Service Co. of New Hampshire (has received overtures from several New England utilities after filing for bankruptcy in March 1988); SCEcorp and San Diego Gas & Electric (merger agreement reached in November 1988 ending San Diego Gas & Electric's previous agreement to merge with Tucson Electric).

[29] Salomon Brothers Stock Research, *Electric Utility Quality Measurements—Quarterly Review*, Jan. 26, 1989, p. 11.

Figure 2-10—Internal Cash Generation and Construction by Investor-Owned Electric Utilities, 1980-90 (billions of dollars)



E = estimate.

SOURCE: Salomon Brothers Stock Research, "Electric Utility Quality Measurements, Quarterly Review," Jan. 26, 1989.

Bond Ratings

Although the utility industry's fundamental financial position has improved substantially over the past decade and is now quite strong, there are at least some indications that this improvement may be offset somewhat by a more risky operating environment. The industry's average bond ratings, for instance, have not improved over the past decade, primarily because ratings agencies believe that improvements in the industry's fundamental financial condition have been offset by increased business risk resulting from the growth of competitive forces and new regulatory approaches. During 1987, all four major utility bond ratings agencies downgraded the ratings of more utility debt securities than they upgraded. The bankruptcy filing by Public Service Co. of New Hampshire in 1988, the first major private electric utility bankruptcy in more than 50 years, may further increase perceptions of risk in this industry by securities ratings agencies. Moreover, the overall improvement in the utility industry's financial position has not been spread evenly throughout the industry. Utilities with nuclear plants still under construction, in particular, appear to remain quite vulnerable, as is reflected in the fact that five such investor-owned utilities carry bond ratings that are below investment grade.

Allowed and Earned Returns

In addition, allowed and earned rates of return in the industry are falling as regulators adjust to the lower interest rate environment of the mid-1980s. As figure 2-11 shows, allowed returns on equity for the industry fell from nearly 16 percent in 1982 to just below 13 percent in 1988—although the spread between utility allowed returns and bond yields has actually widened somewhat during this period. Earned returns, the amounts actually earned by utilities, have also been falling since 1984 and actually exceeded allowed returns in 1987.

Trends in Rate Decisions

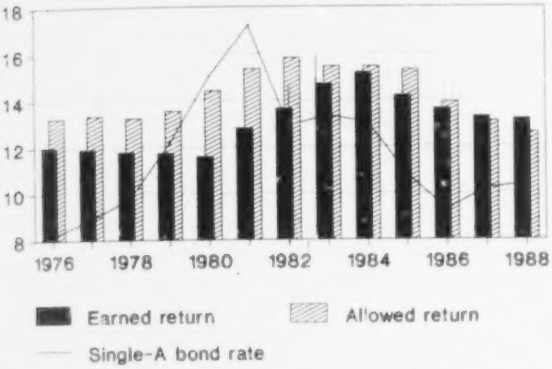
Recent trends in electric rate case actions—shown in table 2-8—confirm that many regulators believe that the industry's rate of return is, if anything, more than adequate. Rate increases granted by regulators have been dropping sharply in recent years due to declining interest rates, lower allowed returns on equity, and decreases in State and Federal income tax rates. In 1987, in addition to approving $2.3 billion in rate increases, regulators ordered more than $1.4 billion in annualized electric rate decreases—

Table 2-7—Capitalization Ratios of Electric Utility Industry, 1965-87

Capitalization	1965	1970	1975	1980	1985	1987
Common equity	38.3%	34.1%	34.3%	36.5%	41.4%	41.5%
Preferred and preference stock	9.3	9.5	12.1	11.7	9.5	7.9
Long-term debt	50.6	53.0	50.8	48.6	48.1	48.2
Short-term debt	1.8	3.4	2.9	3.2	1.0	2.4

SOURCE: Leonard Hyman, *America's Electric Utilities: Past, Present and Future* (Arlington, VA: Public Utilities Reports, 1988 edition); and Salomon Brothers Stock Research, "Quarterly Review," Apr. 15, 1988.

Figure 2-11—Electric Utility Allowed and Earned Returns on Equity, 1976-87



SOURCE: Salomon Brothers Stock Research, "Electric Utility Regulation—Semiannual Review," Sept. 6, 1988.

the first time ever that rate decrease amounts have surpassed $1 billion.[30]

THE EXISTING REGULATORY STRUCTURE

In the United States, Federal, State, and local governments exercise jurisdiction over the activities of the electric power industry. Like other businesses, the electric power industry is subject to laws and regulations governing financial transactions, employment practices, health and safety, and environmental impacts. But unlike other businesses, it (along with segments of the transportation and telecommunications industries) is subject to the additional requirements of public utility regulation. The electric power industry is one of the most heavily regulated with virtually all aspects of power generation, transmission, and distribution under the oversight of State and/or Federal agencies.

The Concept of a Public Utility

Because their activities provide vital services to businesses and communities, public utilities enjoy a special status under State and Federal law that distinguishes them from other enterprises. This status confers specific rights and obligations. Generally, a public utility has:

- an obligation to serve all customers in its service area (within its available capacity limitations);
- an obligation to render safe and adequate service, including meeting foreseeable increases in demand;
- an obligation to serve all customers within each service class on equal terms (i.e., with no unjust or undue discrimination among customers); and
- an obligation to charge only a "just and reasonable" price for its services.[31]

In return for assuming these obligations, the public utility enjoys certain "rights." First, the utility has a right to reasonable compensation for its services, however recovery of a specific authorized rate of return is not guaranteed.[32] Second, through its franchise and certificate of public convenience and necessity, the utility generally is protected from competition from other enterprises offering the same service in the same service territory. Third, the public utility has a right to conduct its operations and render service subject to reasonable rates and regulations. Finally, in many States, public utilities can exercise the right of eminent domain to condemn and take private property for public use where necessary to provide adequate service, subject to the requirement of just compensation to the owner.[33]

Federal and State Regulation of Electric Power

Both State and Federal laws define any entity that sells electricity as a public utility[34] thus bringing

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[30] Edison Electric Institute, "Rate Decrease Amounts Top One Billion Dollars in 1987," *EEI Financial Info*, Apr. 12, 1988.

[31] Charles F. Phillips, Jr., *The Regulation of Public Utilities: Theory and Practice* (Arlington, VA: Public Utilities Reports, Inc., 1984), p. 106.

[32] Regulatory authorities cannot force a utility to operate at a loss. However, at times, the utility may not actually earn its authorized rate of return because of adverse economic conditions or poor business judgment. The rate will be upheld by the courts if it is determined to be reasonable.

[33] Phillips, supra note 31, p. 107.

[34] See, for example, the definition of an electric utility in the Federal Power Act as: "any person or State agency which sells electric energy," 16 U.S.C. 796(22), and the definition of "electric utility company" in the Public Utility Holding Company Act as "any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale." 15 U.S.C. 79b(a)(3).

Table 2-8—Annual Electric Rate Case Actions, 1983-87

Year	Number of rate actions		Total amount (millions of dollars)	
	Increases	Decreases	Increases	Decreases
1983	241	17	5,373.4	59.1
1984	186	19	4,745.0	175.0
1985	127	17	4,989.7	129.7
1986	104	21	2,880.9	383.0
1987	86	117	2,304.3	1,441.8

SOURCE: Edison Electric Institute, 1988.

generators and retail distributors of electricity under regulation. Jurisdiction over the activities of electric utilities is split between the Federal Government and State agencies (including local governments). This division reflects both the historical growth of electric utility regulation in this country, which began at the State and local level, and the Federal Government's constitutional authority over interstate commerce. Most generators are now subject to both Federal and State rate regulation.

The split jurisdiction was formalized with passage of legislation in 1935 that gave the Federal Power Commission authority over interstate transmission and sale of electric power at wholesale.[35] The creation of a strong Federal role in the regulation of interstate activities in electric power was prompted by the 1927 Supreme Court ruling that State regulatory agencies were constitutionally prohibited from setting the prices of electricity sold across State lines because it would violate the Commerce Clause.[36] This decision created a gap in effective regulation of electric utilities.

Federal regulation of interstate and wholesale sales was initially seen as a supplement to State authority to fill a gap where existing State regulation had proven ineffective or unconstitutional. But as interconnections among utilities grew and long-distance transmission increased, virtually all electric power moving over transmission lines was viewed as being in interstate commerce and hence subject to exclusive Federal jurisdiction. Ever more expansive interpretations of Federal jurisdiction have now arguably limited State jurisdiction over wholesale sales and wheeling transactions, even when they involve instate parties.[37]

Federal Regulation

The major Federal regulatory agency for electric utilities is FERC, the successor to the Federal Power Commission. FERC is a five-member independent regulatory commission within the Department of Energy. It derives its primary authority from the Federal Power Act, as amended.[38]

FERC has authority over the prices, terms, and conditions of wholesale power sales involving privately owned power companies and of transmission of electricity at wholesale.[39] Because the power systems in the ERCOT region of Texas, and in Alaska and Hawaii are not synchronously connected to power systems in other States, FERC does not have jurisdiction over most power transactions in these States. FERC must approve sales and mergers of public utilities under section 203 of the Federal Power Act.[40] It has jurisdiction over the issuance of securities and indebtedness of electric utilities.[41]

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[35] Title II of the Public Utility Act of 1935, known as the Federal Power Act, 16 U.S.C. 791a.

[36] *Public Utilities Commission of Rhode Island* v. *Attleboro Steam & Electric Co.*, 273 U.S. 83 (1927).

[37] See *Federal Power Commission* v. *Southern California Edison Co.*, 376 U.S. 205 (1968), also known as *City of Colton* v. *Southern California Edison Co.* See also *Florida Power & Light Co.*, 29 F.E.R.C. 61,140 (1984) in which FERC asserted exclusive Federal jurisdiction over virtually all transmission service in Florida.

[38] 16 U.S.C. 791a.

[39] See secs. 201 and 205 of the Federal Power Act, 16 U.S.C. 824a and 824d, respectively.

[40] 16 U.S.C. 824b.

[41] 16 U.S.C. 824c.

FERC also oversees power pools and interconnections among utilities.[42]

As part of the responsibilities inherited from the Federal Power Commission, FERC oversees and licenses nonfederal hydroelectric projects on navigable waters under Title I of the Federal Power Act.[43] In addition, FERC approves the rates for public power sold and transported by the five Federal Power Marketing Agencies.

The Public Utility Regulatory Policies Act of 1978 (PURPA) amended the Federal Power Act and gave FERC expanded responsibilities for the encouragement of cogeneration and small power production using alternative energy technologies.[44] The goals of PURPA were to advance: 1) conservation of electric energy, 2) increased efficiency in electric power production, and 3) achievement of equitable retail rates for consumers. This was to be achieved in large part by requiring utilities to interconnect with and buy power from cogenerators and small power producers that met standards established by FERC. This requirement was the first major Federal move to open up electricity markets to nonutilities. At the same time, PURPA exempted these qualifying facilities (QFs) from most of regulatory burdens applicable to public utilities under Federal and State law in order to reduce the institutional barriers to QF development.

PURPA requires that electric utilities must offer to purchase electricity from QFs at their avoided costs and to sell electricity to QFs on nondiscriminatory terms and conditions. In addition, utilities must offer to interconnect and operate in parallel with QFs. The rates paid for QF power must: 1) be just and reasonable to electric consumers and in the public interest, 2) not discriminate against QFs, and 3) not exceed the cost of electric energy that the utility would generate itself or purchase from another source.[45] The rates charged to QFs for supplemental or backup power must be just and reasonable and not discriminate against QFs.

FERC was given the lead responsibility to issue regulations and guidelines implementing PURPA, but State regulatory commissions were given the primary authority for setting avoided cost rates and conditions for PURPA purchase and sale contracts. FERC has continuing responsibility for overseeing PURPA implementation and in March 1988 issued three notices of proposed rulemaking (NOPRs) that would alter the original PURPA regulations to correct perceived shortcomings in State avoided cost determinations and to allow the use of competitive bidding in setting QF payments.

In addition to the interconnection and purchase requirements, PURPA also gave FERC explicit, though severely limited, authority to order an electric utility to transmit over its lines power produced by another generator.[46] Whether FERC has any inherent authority to order wheeling services under other provisions of law is a matter of some controversy and debate. Until recently, FERC and many legal experts concluded that FERC had no wheeling authority under the Federal Power Act because Congress had expressly rejected such a provision in passing the Act.[47] Recently, it has been suggested that FERC has the inherent authority to require a utility to wheel power for others as a condition of approving wholesale rates, mergers and acquisitions, or participation in competitive generation markets.[48]

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[42] 16 U.S.C. 824b.

[43] 16 U.S.C. 791a to 823.

[44] Public Law 95-615, 92 Stat. 3117, Nov. 9, 1978.

[45] Public Law 95-615, sec. 210, 92 Stat. 3144, 16 U.S.C. 824a-3.

[46] PURPA secs. 203 and 204 amended the Federal Power Act to add new secs. 211 and 212, codified as 16 U.S.C. 824j and 16 U.S.C. 824k, respectively.

[47] In *Otter Tail Power Co. v. United States*, 410 U.S. 366, at 375 (1973), the U.S. Supreme Court noted in dicta that the Federal Power Act did not grant any authority to order wheeling, but that wheeling could be ordered by the Federal Courts as a remedy under the antitrust laws. A similar conclusion on wheeling authority is reached in National Regulatory Research Institute, *Non-Technical Impediments to Power Transfers*, September 1987, pp. 52-68, although the author notes that FERC may have some as yet untested authority to order wheeling as a remedy for anti-competitive behavior under secs. 205 and 206 of the Federal Power Act, id. at note 45, p. 64. See also *Florida Power & Light Co. v. FERC*, 660 F. 2d 668 (5th Cir. 1981), p. 679. The report of the Conference Committee on PURPA is vague on the extent of any existing wheeling authority FERC might have outside of secs. 211 and 212 and notes that PURPA is not intended to affect existing authority. House Conference Report 95-1750, to accompany H.R. 4018, 95th Cong., 2d sess., Oct. 10, 1978, pp. 91-95, 1978 U.S. Code Congressional and Administrative News 7825-7829.

The Public Utility Holding Company Act of 1935 (PUHCA) was passed in conjunction with title II of the Federal Power Act.[49] It gave the Securities and Exchange Commission (SEC) broad authority over the structure, finances, and operations of public utility holding companies. PUHCA was enacted in response to widespread concern over the influence of a handful of large interstate utility holding companies that by 1932 controlled over 75 percent of the private electric utilities. The holding companies' complex corporate structures and interlocking business arrangements had frustrated both State and Federal oversight of their activities, led to substantial investment fraud, and weakened or bankrupt a number of local gas and electric utilities.[50] PUHCA was intended to limit severely the use of the holding company structure and to force the regional consolidation of the existing large multi-State holding companies.

Under PUHCA any company that owns or controls more than 10 percent of the voting securities of a public utility is considered to be a public utility holding company. An electric utility company is any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale. The holding companies are subject to extensive regulation of their financial activities and operations under PUHCA. Public utility holding companies can qualify for an exemption from the most stringent regulatory oversight of PUHCA if they operate wholly within a State, or in contiguous States, or the company is only incidentally a holding company, is primarily engaged in a business other than the public utility business, and does not derive a material part of its income from the public utility business.[51] Non-exempt entities are registered holding companies and are limited in their operations to "a single integrated public-utility system, and to such other businesses as are reasonably incidental, or economically necessary or appropriate [there]to." Integration means that the utility operations are limited to a single area or region of the country. Registered holding companies must obtain SEC approval of the sale and issuance of securities; transactions among their affiliates and subsidiaries; and services, sales, and construction contracts. In addition the companies must file extensive financial reports with the SEC. In contrast, exempt companies need only file limited annual reports with the SEC.

The REA also exercises some regulatory oversight of cooperatives holding Federal loans. The extent of this regulation is primarily directed at assuring the financial viability of the cooperative entities to repay their Federal loan obligations. At times the REA has ordered cooperatives to raise rates to their customers to cover costs.

State Regulation

State regulation of electric power is diverse and only broad generalizations can be made. State regulation is conducted by multimember boards or commissions whose members may be either appointed or elected. The utilities under State jurisdiction vary—some States regulate all utilities, including publicly owned systems and cooperatives, while others limit jurisdiction to investor-owned systems and leave regulation of municipal systems to local governments. In addition to control over prices, States or local governments control market entry and determine who may operate as an electric utility by granting certificates of public convenience and necessity and awarding franchise territories.

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[48] In *Re Utah Power & Light Co., et al.* (Oct. 26, 1988), FERC approved the merger of Utah Power & Light Co. into Pacific Power & Light Co. subject to the condition that the merged companies provide firm wholesale transmission services at cost-based rates to any utility that requested such service. The condition was necessary to prevent the future exercise of market power by the new company to foreclose access by competitors to bulk power markets. The decision was reached under sec. 203 of the Federal Power Act which requires commission approval of mergers and acquisitions. The extent of any inherent conditional authority of FERC to order wheeling under other sections of the Federal Power Act is still uncertain. FERC has solicited comments on imposing "wheeling in" and "wheeling out" conditions on utilities participating in bidding programs. Notice of Proposed Rulemaking on Regulations Governing Bidding Programs (18 CFR Parts 35 and 293), Docket No. RM88-5-000, Mar. 16, 1988, pp. 87-91. "Wheeling in" would require a utility bidding on the capacity needs of another utility to agree to provide firm transmission services to the purchasing utility for successful bidders that are located in its service area or that can reach one of its interconnection points. "Wheeling out" would require a utility bidding to supply its own capacity needs to provide firm transmission services in and through its service area to unsuccessful bidders that wished to sell to another wholesale purchaser. For an expansive exposition of the argument that FERC has and is required to use conditional wheeling authority to deal with potentially anti-competitive situations, see the comments of the Electricity Consumers Resource Council et al. filed in Docket RM88-5-000, July 18, 1988, and Reply Comments filed Sept. 13, 1988.

[49] Act of Aug. 26, 1935, c. 687, Title I, sec. 33, 49 Stat. 438, 15 U.S.C. 79.

[50] For a discussion of the structure and influence of the holding companies, see Leonard S. Hyman, *America's Electric Utilities: Past, Present and Future*, 3d ed. (Arlington, VA: Public Utilities Reports, Inc., 1988), pp. 71-83.

[51] 15 U.S.C. 79c.

All States regulate retail prices of electricity. In setting retail rates, State regulators must approve a level that provides a reasonable rate of return to the utility which will cover its costs of providing service plus a profit. Under various formulations, many States require that utility investments be determined to be prudent and "used and useful" before they can be recovered through retail rates. Some States allow recovery for plants under construction, while others defer recovery until the plant is actually in operation.

Many States also regulate other aspects of utility operations in some detail including planning and determination of resource needs including new generation, bulk power purchases, and construction of transmission and distribution facilities.[52] A number of States regulate the siting of utility facilities either through the public utility commission or a separate siting agency.[53]

Several States have included wheeling provisions in their competitive bidding programs. However, the extent to which State regulatory authorities can require wheeling is uncertain because of the possibility of preemption by FERC under section 201(b) of the Federal Power Act.[54] FERC has asserted authority over the rates and conditions of transmission in interstate commerce and has argued that this preempts State regulation of these matters.[55] But FERC has so far declined to resolve the issue of whether FERC jurisdiction also preempts State authority to order wheeling.

While States have exclusive retail rate jurisdiction, under the *Narragansett* doctrine they must generally pass through wholesale rates approved by FERC.[56] The extent to which FERC determinations of the reasonableness of wholesale rates preempts State consideration of the retail impacts of those same rates is a matter of some controversy.[57] The strain arises because State regulatory programs and the considerations used in setting rates are generally far more extensive than FERC's. In some cases, requiring States to adopt without question FERC's wholesale rate determinations in setting retail rates would preclude States from exercising their own regulatory authority over issues normally within their jurisdiction.

The major limitation on Federal preemption is found in the *Pike County* exception, which affirmed the right of a State commission to examine the prudence of a wholesale power purchase contract and to disallow the pass through of FERC-approved wholesale costs if lower cost power supplies were available elsewhere.[58] The issue of whether States can review the prudence of wholesale power contracts will become especially critical if proposals to create a competitive generating sector result in utilities relying more heavily on bulk power purchases that, except for QF transactions, fall within FERC's jurisdiction. The vitality of the *Pike County* exception has been cast into doubt by the Supreme Court's 1988 decision in *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore* that rejected State efforts to deny a rate increase based on FERC's allocation of the costs of a nuclear unit built to meet the needs of an integrated interstate holding company system on the grounds that the local subsidiary's participation in the project was imprudent.[59] A State prudence inquiry was preempted even though FERC had not examined the issue during wholesale rate proceedings. The State regulators' only recourse is to challenge the prudence of the wholesale arrangements before FERC. Whether the *Mississippi Power & Light* decision is limited to the particular situation of interstate holding companies or whether it marks further limitations on the powers of State regulators is not yet known. Resolution of this controversy over conflicting Federal and State jurisdictional claims will be one of the major public policy issues in any transition to a more competitive electric power industry.

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[52] For a summary of State requirements for utility planning and forecasting requirements, see Public Utilities Commission of the State of Ohio, *Transmission Line Certification and Siting Procedures and Energy Planning Processes: Summary of State Government Responses to a Survey by the National Governors' Association Task Force on Electricity Transmission*, OTA contractor report, July 1988.

[53] See the discussion of State siting requirements in ch. 7 of this report.

[54] 16 U.S.C. 824b. See discussion of this issue in National Regulatory Research Institute, supra note 47, pp. 70-78.

[55] *Florida Power & Light Co. and Florida Public Service Commission, et al.*, 29 F.E.R.C. 61,140 (1984). See also the remarks of FERC Commissioner Charles Trabandt that FERC may not acquiesce in State efforts to require wheeling under competitive bidding programs. "Trabandt: Generic Action by FERC Unlikely on Transmission Access," *Electric Utility Week*, Feb. 13, 1989, pp. 1-2.

[56] This rule was set forth in *Narragansett Electric Co.* v. *Burke*, 119 R.I. 559, 381 A.2d 1358 (1977), cert. denied, 435 U.S. 972 (1978), one of a series of State court decisions that recognized Federal preemption.

[57] For discussion of these issues see the following: Ronald D. Jones, "Regulations of Interstate Electric Power: FERC versus the States," 2 *Natural Resources & Environment* 3, Spring 1987; Lynn N. Hargis, "The War Between The Rates Is Over, But Battles Remain," 2 *Natural Resources & Environment* 7, Spring 1987; and Bill Clinton, Robert E. Johnston, Walter W. Nixon, III, and Sam Bratton, "FERC, State Regulators and Public Utilities: A Tilted Balance?" 2 *Natural Resources & Environment* 11, Spring 1987.

[58] *Pike County Light & Power Co.* v. *Pennsylvania Public Utility Commission*, 77 Pa. Comm'w. 268, 465 A. 2d 735 (1983). The potential exception was apparently accepted by FERC in *Pennsylvania Power & Light Co.*, 23 F.E.R.C. 61,005 (1983) and noted by the U.S. Supreme Court in *Nantahala Power & Light Co.* v. *Thornburg*, 106 U.S. 2349 (1986).

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[59] *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, No. 86-1970, June 24, 1988.

Chapter 3

Alternative Scenarios for Increasing Competition in the Electric Power Industry

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Chapter 3

Alternative Scenarios for Increasing Competition in the Electric Power Industry

This chapter describes the five alternative institutional and regulatory scenarios for increased competition in the electric power industry that were developed by OTA and which are used throughout this report.

INTRODUCTION

There have been many proposals for revamping the electric power industry through competition, deregulation, and restructuring, but few have been sufficiently detailed, particularly in the area of transmission systems operations, to support the kind of analysis required for this assessment.[1] It was necessary to explore how possible regulatory futures of the electric power industry might evolve before examining the technical feasibility of expanded competition. OTA defined five alternative economic and regulatory scenarios to capture a reasonable range of industry futures and to form the basis of our technical analysis. The major features of the scenarios are summarized in table 3-1.

The scenarios range from scenario 1, which makes modest changes in the regulatory procedures for approving new plant construction with no legislative expansion of transmission access, to scenario 5, which would separate the industry into generation, transmission, and distribution sectors and impose common carrier obligations on transmission companies. Four of the scenarios would expand access to transmission services; two scenarios would allow retail customers to seek wheeling orders. The scenarios pose very different implications for the future direction of the electric power industry and its technical and institutional infrastructure. The scenarios derive important elements from some recent proposals for regulatory reform and structural change in the electric power industry, but are not identical with any one of them.[2]

In discussing scenario implementation, OTA generalizes about how electric utilities would be affected and how State regulation might be adapted. The typical utility structure under the scenarios is the vertically integrated investor-owned utility. This model, while applicable to utilities owning over 70 percent of the our generating capacity, does not cover all of the diverse combinations of utility structure, ownership, and State regulation characteristic of the Nation's electric power industry. For many aspects of the scenarios, the ownership structure of the utility is less important than whether the utility controls and operates generating, transmission, and distribution facilities. OTA believes that these generalizations are sufficiently representative of most of the utilities and State regulatory schemes to allow us to draw supportable conclusions about the overall impacts of the scenarios.

The scenarios do not exclude public power agencies or consumer cooperatives from full participation in the competitive generation sector. Although scenarios 4 and 5 involve significant disintegration and restructuring of the electric power industry, they do not include provisions for "privatizing" Federal and other publicly owned power systems. A detailed consideration of the legal, economic, and political implications of such proposals is beyond the scope of this report.

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[1] For background information contrasting past proposals for electric power industry reform see: Paul L. Joskow and Richard Schmalensee, *Markets for Power: An Analysis of Electrical Utility Deregulation* (Cambridge, MA: The MIT Press, 1983); Theodore Barry & Associates, "A Study of Aggregation Alternatives in the U.S. Electric Utility Industry," December 1982, prepared for the U.S. Department of Energy, Director, Policy Planning and Analysis, Division of Electric Utility Policy (available through National Technical Information Service), DOE/RG/10295-1; U.S. Department of Energy, Office of Policy Planning and Analysis, "Deregulation of Electric Power: A Framework for Analysis, A Draft Discussion Paper, Phase I Report," September 1982 (DOE/NBB-0021), prepared by the Massachusetts Institute of Technology, under contract number Ex-76-A-012295 (available through National Technical Information Service); and Edison Electric Institute, Economics Division, "Alternative Models of Electric Power Deregulation," May 1982 (prepared by NPS Energy Management, Inc.).

[2] For example, scenario 2 transmission access procedures are based in part on recommendations of the Electricity Consumers Resource Council, and scenario 3 includes elements of competitive bidding proposals by FERC Chairman Martha Hesse and the Keystone Electricity Forum, among others.

Table 3-1—Summary of Alternative Scenarios

Scenario 1 Strengthening the Regulatory Bargain	Scenario 2 Expanding Transmission Access and Competition in the Existing Regulated Utility Structure	Scenario 3 Competition for New Bulk Power Supplies	Scenario 4 Competition for All Bulk Power Supplies	Scenario 5 Common Carrier Transmission Services in a Disaggregated Industry Structure
• Industry consists of a mix of vertically integrated utilities, IOUs, public power, cooperatives, Federal power authorities, self-generators, QFs, and IPPs. • Existing regulatory structure with State preapproval of new generating projects and periodic prudence reviews during planning and construction. • Negotiated transmission access arrangements. • Traditional system coordination and control by integrated utilities or control centers. • Prices set by regulatory proceedings and cost of service. Transmission prices and wholesale rates set by FERC (including approval of negotiated IPP power purchases). State oversight of retail rates and PURPA implementation. • Federal and public power agencies and cooperatives affected only to the extent State law provides.	• Industry consists of existing mix of entities. • Existing regulatory structure with wider QF eligibility under PURPA including full utility ownership/control of QFs (may require amendment of PURPA). • New Federal wheeling authority under a public interest standard for wholesale and retail transmission access (requires amendment of the Federal Power Act). • Traditional system coordination and control by integrated utilities or control centers with contracts for unbundled services. • Prices set by regulatory proceedings and cost of service. Transmission prices and wholesale rates set by FERC (including approval of negotiated IPP power purchases). State oversight of retail rates and PURPA implementation. • Federal and public power agencies and cooperatives affected only to the extent State law provides.	• Existing mix of generating entities expanded by IPPs and unregulated utility generating subsidiaries. • Existing regulatory structure with market-based rates for new competitive generation. Utilities use all source procurement for new bulk power needs. Contracts awarded to lowest cost supplier with consideration for non-price factors. • Transmission access provided by utilities as a bidding condition, or by privately negotiated arrangements, or under new Federal public interest wheeling authority (no retail wheeling). • Traditional system coordination and control by integrated utilities or control centers. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Retail and transmission prices set by regulatory proceedings. Wholesale power prices set through competitive procurement except for cost-base plants built by utility as last resort supplier. State and Federal regulators oversee terms and conditions of wholesale sales. • Federal and public power agencies, and cooperatives can participate in competitive generating sector to extent provided by Federal and State law and policy.	• Industry structure: Ownership of competitive generating sector segregated from transmission and distribution sectors. • New Federal and State regulatory systems. Price and entry regulation of generation sector replaced with competitive market. Continued regulation of transmission and distribution utilities and retail sales. • Revised Federal wholesale wheeling authority. Transmission utility to plan for and provide nondiscriminatory access for bulk power supplies. • Most of traditional utility system planning and coordination taken over by transmission and distribution entities. Competitive generators plan and build generation. Transmission operator assumes responsibility for bulk power system control and operation. Distribution utility retains retail obligation to serve. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Bulk power prices set by market through bidding, negotiation. Transmission and retail prices are set by regulatory proceedings. Some State and Federal oversight of competitiveness of generation markets and prudence of bulk power contracts. • Federal and public power agencies, cooperatives can participate in competitive generating sector to extent provided by Federal and State law and policy.	• Ownership and control of existing integrated utility industry is disaggregated into separate generation, transmission, and distribution segments. • New Federal and State regulatory system. Price and entry regulation of generation replaced with competitive markets. Distribution utilities' services and retail prices remain regulated. Transmission prices and activities are strictly regulated. • Transmission sector operates as a common carrier providing nondiscriminatory access to all wholesale and retail customers. Reasonable conditions on reserving transmission services may be imposed. • Bulk system planning and coordination is split among generation, transmission, and distribution entities. Generators identify, plan, and build new generation in response to market signals. Transmission utility assumes responsibility for reliability of bulk system operations. Responsibility for estimating demand and securing adequate power supplies rests with distribution utilities. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Bulk power prices set by market. Transmission and retail prices are set by regulatory proceedings. Some State and Federal oversight of competitiveness of generation markets and prudence of bulk power contracts. • Federal and public power agencies, cooperatives can participate in competitive generating sector to extent provided by Federal and State law and policy.

SOURCE: Office of Technology Assessment, 1989.

SCENARIO 1

Reaffirming the Regulatory Compact

Under the traditional "regulatory contract," a public utility is guaranteed the opportunity to recover all prudent investment committed to public use and to earn a competitive rate of return on its investment. In exchange, the utility assumes the legal obligation to provide adequate and reliable service at reasonable rates to all customers located in its exclusive franchise territory. Scenario 1 reflects the view that only modest changes in existing arrangements and institutions governing the industry are needed to assure continued adequate and reliable electric power supplies. This scenario differs from the status quo by the adoption of measures to reaffirm the regulatory compact between utilities and regulatory authorities (on behalf of utility customers) through:

1. changes to State ratemaking policies to reduce the investment risk for new construction and to allow utilities to attract needed capital;
2. the modification of rules under the Public Utility Regulatory Policies Act of 1978 (PURPA) to address perceived imbalances in the implementation of avoided cost pricing for qualifying facility (QF) payments;[3] and
3. the adoption of measures to encourage greater access to transmission services for bulk power transfers and the construction of additional transmission capacity.

Proponents believe that a major benefit of regulatory reform for utilities would be the enhanced expectation that over the long term they will be able to recover their prudent capital investment and earn a competitive return for their shareholders. At the same time, customers would be assured of adequate, reliable power supplies at reasonable rates. Some analysts speculate that reduced regulatory risks might eventually lead to savings for consumers from a lowering of capital costs of new utility construction.[4] Some proponents of this scenario argue that more drastic reforms of utility regulation are unnecessary because the problems of the 1970s and 1980s were the result of an unfortunate and unique convergence of events and trends that are unlikely to be repeated, and that the regulatory system and domestic utility industry have largely adjusted to changed conditions. Furthermore, the flexibility with which electric utilities and the regulatory system have responded to recent financial difficulties and competitive pressures attests to the soundness of current institutions.

Transmission access and wheeling arrangements would be negotiated between the participants on a voluntary basis. The Federal Energy Regulatory Commission (FERC) would retain its authority over transmission rates and interstate and wholesale power sales. States would exercise jurisdiction over resource planning, expansion, retail rates, and distribution. Public power agencies and cooperatives would continue to be regulated as now, subject to varying degrees of oversight by Federal and State authorities. These changes may give requirements customers greater input and oversight of power supply decisions by wholesale utilities.

Utilities would remain the primary providers of electric power under scenario 1. Cogenerators, self-generators, and independent power producers (IPPs) would continue to exert competitive pressures on utilities, but, except for PURPA qualifying facilities, alternative generating sources would not be given any special status or preference under State or Federal regulation.

Background

Much of the current interest in increasing competition in generation can be attributed to the problems encountered by the electric power industry over the past 15 years in dealing with declining growth rates, excess capacity, rising fuel costs, and steeply escalating construction costs (especially for nuclear plants).[5] Billions of dollars in new, large-baseload generating plants were canceled or deferred.[6] Rising utility costs and sharp rate hikes in the 1970s reversed the postwar trend of steadily declining electricity prices and prompted close regulatory scrutiny of utility performance and rate requests. Eventually regulators disallowed recovery of large amounts of imprudent utility investment in both cancelled and completed plants.[7] The specter of disallowances through "after-the-fact" prudence reviews contributed to a growing perception among many in the utility industry and the investment community that the long-standing regulatory compact had been seriously impaired. Many utilities felt that they were no longer assured an opportunity to recover their capital investment and earn a fair return on investment in exchange for their obligation to serve. In comparison with other industries, many utility stocks posted lower returns to investors during the early 1980s.

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[3] In some cases these changes would lower avoided cost rates, but in others it is conceivable that unrealistically low avoided cost rates would be increased.

[4] Public utility commissions might lower the authorized rate of return for utilities because of the reduced regulatory risk, but some analysts question whether preapprovals would actually lead to a reduction in the risk component of capital costs as reflected in market rates. See National Regulatory Research Institute, *Commission Preapproval of Utility Investments* (Columbus, OH: National Regulatory Research Institute, 1981, reissued 1987), hereafter referred to as "Preapprovals."

Spending on new plant construction has dropped sharply in recent years. The most obvious causes are the completion of large construction projects begun in the 1970s and slow growth in electricity use. Some, however, see this drop as evidence that the industry as a whole has become substantially more risk averse and has adopted a capital minimization strategy in response to increased uncertainty over regulatory decisions and greater unpredictability in future demand growth. Some energy analysts view this hiatus in new plant construction with alarm because they fear additional baseload capacity may be needed as early as the mid-to-late 1990s if electricity demand growth increases significantly.[8]

PURPA has increased the amount of nonutility generation and cogeneration and spurred investment in and commercialization of alternative energy technologies. The competitive pressures created by the growth of PURPA cogeneration have forced many utilities to engage in aggressive cost-cutting to lower rates to avoid the loss of industrial customers. At the same time, PURPA has further compounded the uncertainties facing utilities. As implemented in some States, PURPA also has required some utilities and their ratepayers to pay for unneeded energy or QF capacity under long-term fixed-price contracts at avoided cost prices that are higher than the utilities' current marginal costs of generating electricity. Moreover, many critics of PURPA argue that it has disproportionately favored greater reliance on oil and natural gas as fuels.

Undoubtedly, some of the impacts of PURPA reflect the initial difficulties and uncertainties in implementing a complex regulatory scheme. Other problems, however, are caused by the current surplus of generating capacity and lower fuel prices—circumstances that arguably are different from those envisioned when PURPA was enacted in 1978 in an era of rising fuel costs, projected high electricity demand growth, and fears of future energy shortages. Already, many States have initiated changes in their PURPA implementation programs to address these changed circumstances and reduce avoided costs while at the same time preserving PURPA's incentives for alternative generators.

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[5] Another reason for the interest in expanding competition is the political preference among some economists and policymakers in favor of market-based institutions and against regulated monopolies. Less reliance on regulation and greater reliance on increased competition in power supplies are seen as mechanisms for attaining the goal of economic efficiency.

[6] U.S. Congress, Congressional Budget Office, *Financial Condition of the U.S. Electric Utility Industry* (Washington, DC: U.S. Government Printing Office, March 1986).

[7] Under many State regulatory statutes, a utility investment in a new plant must be prudent and used and useful (put into service) before it can be placed in the rate base and costs recovered from ratepayers. Prudence reviews are regulatory examinations of the appropriateness of utility demand projections, construction practices, and management decisions and are a precondition for adding a new facility to the ratebase. The reviews are typically conducted after the plant is completed. Prudence reviews have lead regulators to disallow all or part of investments in large coal and nuclear plants because of mismanagement and uncontrolled costs and, in some cases, because the completed plant proved to be excess capacity when projected demand growth did not materialize. Some industry analysts contend that prudence reviews have shifted the risks from ratepayers to shareholders and utilities and made it more difficult for utilities to commit capital for construction. Others contend that utilities and shareholders always bore these risks, but that they had historically been minimal until the highly inflationary and turbulent 1970s.

[8] For example, see: J. Steven Herod and Jeffrey Skeer, "A Look at National and Regional Electric Supply Needs," paper presented at the 12th Energy Technology Conference and Exposition, March 1985; U.S. Department of Energy, Deputy Assistant Secretary for Energy Emergencies, Staff Report, "Electric Power Supply and Demand for the Contiguous United States, 1997-1996," DOE/E-0011 (Springfield, VA: National Technical Information Service, February 1988); Peter Navarro, *The Dimming of America: The Real Costs of Electric Utility Regulatory Failure* (Cambridge, MA: Ballinger Publishing Co., 1985).

From the perspective of some utilities, PURPA contributed to the further impairment of the traditional utility bargain because, while it left utilities with the obligation to assure adequate, reliable electricity service, it diminished their control over the sources and costs of generation.

Time, lower fuel prices, and lower inflation rates have abated many of the financial threats to the electric utilities.[9] There remain, however, some problems of uncertainty and delay attributed to both the regulatory process and prudence reviews of generating plant construction costs. There is some agreement among regulators and utilities that targeted regulatory reforms would help avoid the conflicts of recent years and restore a balance to the regulatory bargain by assuring the industry of recovery of future prudent investments in new facilities, if needed, while offering similar assurances to consumers and regulators that new capacity costs will be kept under control.

Implementation

The primary responsibility for implementing scenario 1 would rest with State governments. Few changes to Federal law and regulation would be necessary. The major Federal statutory and regulatory structure governing the electric power industry today would remain essentially unaltered. In particular, PURPA, the Federal Power Act, and the Public Utility Holding Company Act (PUHCA) would be untouched and existing statutory standards would not be loosened or expanded substantially by administrative or judicial interpretations. Scenario 1 would not, however, preclude certain relatively selective, but possibly significant, changes in existing administrative rules governing industry structure and operations. For example, FERC might make minor changes or clarifications in rules governing utility avoided costs for purchases from qualifying facilities under PURPA. FERC might impose more stringent technology or efficiency standards on QFs to discourage the proliferation of "PURPA machines." Similarly, FERC could continue its efforts to encourage greater amounts of voluntary wheeling by utilities and to provide additional incentives for expanded intersystem bulk power transactions. Examples include the Western Systems Power Pool Experiment and approvals of more flexible transmission pricing schemes in individual cases.

Transmission access and wheeling rates for wholesale and retail customers under this scenario would depend on voluntary agreements negotiated with the utilities controlling transmission facilities. FERC would oversee wheeling rates.

Federal authority to issue wheeling orders under the Federal Power Act and PURPA would remain limited. The Nuclear Regulatory Commission could order wheeling as part of licensing of new nuclear plants, however, it is unlikely that any new orders will be issued. FERC jurisdiction would largely be limited to setting wheeling rates and approving various proposals and experiments among utilities. Some States would continue to assert authority to require intrastate wheeling as a condition of State initiatives.[10] Antitrust considerations could provide some source of mandatory wheeling as part of a court order or settlement, but such wheeling orders are expected to be rare.

The current statutory split between Federal and State jurisdiction over regulation of electric utilities would remain largely undisturbed. With the existing trend toward greater use of bulk power sales, however, it is conceivable that a greater share of power costs might shift from State to Federal regulatory jurisdiction. Modified State regulatory procedures for review and approval of new plant construction would offer stronger assurances to utilities of recovery of investment than the current system. These changes would likely require State legislation and would probably include a more direct and active role by utility commissions (and the public) in the planning and oversight of new generation sources and transmission facilities.[11] Some observers believe, however, that many States would not significantly alter their existing regulatory procedures because they have already adopted similar reforms in response to the problems of slow growth rates, inflation, cost-overruns, soaring fuel prices, and excess capacity that stressed utilities during the 1970s and early 1980s.

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[9] Many utilities have regained their healthy financial status and are projected to have favorable cash flows in the late 1980s-1990s. See ch. 2 of this report.

[10] The success of these efforts is open to doubt. Texas requires utilities to wheel QF power to other utilities. Texas may escape challenge because its transmission grid is physically isolated from other interconnected systems and thus arguably cannot be said to affect interstate transmission flows. Other States are potentially subject to FERC challenges to their authority. New York and Massachusetts require wheeling as a condition of participation in their bidding programs. Florida's attempts to require intrastate wheeling, including self-service wheeling, have repeatedly been challenged by FERC and by several Florida utilities, arguing that Federal law preempts State control over rates, and the terms and conditions of wheeling transactions. *Florida Power & Light, Petition for Declaratory Order from FERC*, EL87-19-000, filed Mar. 11, 1987.

Rolling Prudence Reviews. One regulatory reform that addresses the utilities capital attraction problem is a preapproval process for construction of new generating and transmission facilities coupled with periodic prudence reviews.[12] These determinations would be in addition to State least-cost planning requirements. Regulators and utilities would agree in advance as to the need, type, cost, and rate implications of major new projects. These hearings would allow participation by consumers. Following initial approval, projects would be subject to regularly scheduled prudence reviews from inception to completion. Utilities would be assured recovery of all expenses incurred up to the most recent prudence determination, except of course for losses due to reckless, improper, or negligent actions of the utility. This process has been characterized as a "rolling prudence review" in contrast to the post-construction prudence reviews now common under many State regulatory programs.[13] Preapproval is not equivalent to adoption of a rate scheme that allows recovery for Construction Work in Progress (CWIP) in the rate base before the plant actually is in use. Under the rolling prudence concept, a new plant would become recoverable as part of the rate base only after it began operating and was determined to be "used and useful."

If the circumstances underlying an initial approval of new capacity changed, periodic regulatory reviews could allow projects to be canceled or modified midcourse, but the utility would still be entitled to recover in the rate base the value of its prudent investment to date plus a reasonable return over any recovery period.[14] If the utility chose to continue construction, it would receive no guarantees from that point on that the remaining costs would be allowed into the rate base. When and if the facility began operation, the public utility commission would decide whether the expenditures were prudent. Some utility executives argue that such a regulatory program would "fairly balance the risk to consumers and investors alike and give assurance of adequate and reliable supply of electric power in the future."[15] In effect, the traditional regulatory bargain would be restored and strengthened, but it would be more comparable to an explicit contract between the utility and the regulatory commission on behalf of the customers.

Institution of a rolling prudence review for new construction projects would reduce the utility's management control over major investment decisions. In some States, however, there is already an extensive degree of regulatory involvement in all aspects of utility investment decisionmaking and, to some degree, this scenario would simply constitute a formal recognition of a regulatory system that already exists, except perhaps for the guarantees accorded to the utility.

A system of rolling prudence reviews is consistent with other current trends in regulatory treatment of utility resource expansion planning and construction. Other regulatory initiatives have been proposed or adopted in recent years to restore the utility's expectation that it will recover its prudent investments or to enhance its cash flow to fund construction. Examples include automatic fuel adjustment clauses, incentive rates, performance bonuses and penalties, advance caps on construction reimbursement, and inclusion of the value of CWIP in the ratebase.[16]

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[11] State regulatory authorities in Massachusetts have adopted a preapproval process for new capacity. Massachusetts Department of Public Utilities, "Pricing and Rate-making Treatment To Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities," D.P.U. 86-36-C, May 12, 1988.

[12] See "Presentation of Richard E. Disbrow at a Seminar for Virginia's Legislative Leadership and Energy Committee Members, Aug. 10, 1987" for a discussion of this approach. This strategy is also based in part on the remarks of Richard E. Disbrow at the OTA Workshop on Alternative Scenarios for Increasing Competition in the Electric Power Industry, Sept. 28, 1987; and on NRRI, "Preapprovals," supra note 4.

[13] The prime attractions of a rolling prudence scheme are that it reduces some of the risk in utility capital investments, while the expanded role in planning, approval, and scheduled project reviews offers equivalent protections and controls for regulators and consumers.

[14] Many State regulatory authorities have historically allowed utilities to recover the full costs of canceled plants plus a reasonable return on investment. Some States may, however, be restricted by State authorizing legislation that limits recovery to capital plant expenditures that are both prudent and used and useful, therefore requiring a facility to actually be in operation before any recovery can be placed in the ratebase. See NRRI, "Preapprovals," supra note 4.

[15] Disbrow, supra note 12.

Regulatory reforms aimed at reducing or shifting risk in constructing new large baseload plants may not, however, actually result in the immediate construction of any such plants. Other considerations such as the extent of existing reserve capacity, increased uncertainty in future demand growth, and greater volatility in fuel prices may lead utilities to conclude it is more prudent and cost-effective to build smaller increments of new generation and to buy power from other sources for the foreseeable future.[17]

Under scenario 1 many ongoing State regulatory initiatives could be expected to continue. State commissions would likely continue their efforts to encourage utilities to expand their bulk power procurement practices to include consideration of QFs, other utilities, and independent power suppliers.[18] Under the more standard State PURPA programs, the commissions might review previously established avoided cost rates. In some cases, lower fuel costs and existing capacity surpluses could yield lower avoided cost rates. These changes could lead some higher-cost PURPA projects to drop out. In other cases, reviews may lead to increases in existing low avoided cost rates encouraging QF development. The basic PURPA incentive structure would still remain. Utilities would still be obligated to purchase power generated by QFs at avoided cost rates. QFs would retain the protection of existing long-term capacity contracts at avoided cost pricing with host utilities.

States could continue to encourage greater coordination of utility planning and operations through centralized dispatch, power pools, and brokerage arrangements. The States would also continue their efforts to promote workable regional power supply planning arrangements and new means of developing needed interregional transmission capacity. Preapproval will eventually require most State regulatory agencies to increase their expertise in system planning and load forecasting.

Industry Structure. Under scenario 1 the electric power industry would consist of the current mix of investor-owned utilities, public power agencies, cooperatives, Federal power authorities, self-generators, small power producers, QFs, and IPPs. As now, vertically integrated, investor-owned utilities will dominate the generation, transmission, and retail distribution segments of the power industry. Recent trends toward limited industry restructuring through mergers, acquisitions, and internal reorganizations can be expected to continue within the constraints imposed by existing law.

The trend toward greater bulk power competition would continue as power suppliers, sellers, buyers, and State regulatory commissions cope with pressures from prices and technology. In some States or regions a de facto competitive market in bulk power supplies will continue to evolve if FERC maintains its "hands off" approach to reviewing these interutility transfers. Utilities will continue to increase bulk power transfers.

The role of IPPs, and especially utility-affiliated IPPs, remains unsettled because, unlike QFs, they would not be exempt from coverage by the Federal Power Act or PUHCA. Without PURPA purchase requirements, IPPs would have to compete on the underlying economics of their projects. Non-QF cogenerators and IPPs could continue to contract for the sale and transmission of power to utilities and other purchasers, however, provided suitable arrangements can be negotiated.

System Operations and Planning

Scenario 1 would have little or no impact on system operations and closely resembles the status quo. Table 3-2 summarizes the system operating requirements under the scenarios. Responsibility for

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[16] See Joseph P. Kalt, Henry Lee, and Herman B. Leonard, "Re-Establishing the Regulatory Bargain in the Electric Utility Industry," Discussion Paper Series (E-87-02), Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University, Cambridge, MA, March 1987; Leland L. Johnson, *Incentives To Improve Electric Utility Performance: Opportunities and Problems* (Santa Monica, CA: Rand Corp., March 1985); and NRRI, "Preapprovals," supra note 4.

[17] This utility investment preference was previously noted by OTA, U.S. Congress, Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990s*, OTA-E-246 (Washington, DC: U.S. Government Printing Office, July 1985), ch. 3.

[18] This approach is different from scenario 3 which would require the use of competitive procurement procedures for all new bulk power supplies.

Table 3-2—Alternative Scenarios: Summary of System Operations, Planning, and Development

	System operation	System planning and development		
Scenario	Reliability, dispatch and coordination	Generation	Transmission	Distribution
1. Strengthening the regulatory bargain.	Utility control center. Control of nonutility generation set by contract.	Utility obligation to plan, build, and purchase. QFs market under PURPA. IPPs negotiate contracts.	Utility responsibility.	Local utility responsibility.
2. Expanding transmission access and competition in the existing regulated industry structure.	Similar to 1 with greater reliance on contractual provisions for nonutility generation control and wheeling.	Similar to 1 with expanded QF and IPP participation.	Same as 1, but States may require utilities to plan and build adequate transmission capacity for regional needs including retail wheeling.	Same as 1.
3. Competition for new bulk power supplies.	Same as 2.	Utility obligation to plan and secure adequate new supplies through competitive means. Generators include utilities, QFs, IPPs, and host utility affiliates.	Same as 2, but no retail wheeling obligation.	Same as 1.
4. Competition for all bulk power supplies.	Transmission utility assumes bulk system control. Operational responsibilities of generators and distribution utilities set by contracts with customers and transmission utilities.	Generators plan and build in response to perceived market needs and solicitations by transmission-distribution utilitites.	Transmission utility obligation to plan and build adequate capacity for instate/regional wholesale needs.	Local retail utility obligation to plan and contract for adequate supplies. Utility may participate in load management and conservation. Transmission utility may provide brokering services.
5. Common carrier transmission services in a disaggregated industry structure.	Same as 4.	Generators plan and build in response to perceived market needs and solicitations by local distribution utilities and transmission companies as brokers.	Transmission utility obligation to plan and build adequate capacity for foreseeable needs as common carrier for regional wholesale and retail customers.	Same as 4.

SOURCE: Office of Technology Assessment, adapted from Power Technologies, Inc., *Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access, and Nonutility Generation*, OTA contractor report, Mar. 30, 1988.

maintaining day-to-day system reliability and coordination of generation and transmission resources would rest with the local utility or centralized control center (under a coordination or power pool agreement).[19] Interutility agreements and operating practices, as well as NERC regional protocols, would continue to govern cooperative activities among utilities. Operational responsibilities and technical standards for nonutility or third-party power suppliers would be based on contract terms with the local utility. As under existing law, State regulators would have the authority to rule on the reasonableness of utility technical specifications in cases of disputes between utilities and third-party generators.[20]

The local utility or regional control center would determine the order of dispatch, maintenance scheduling, and unit loading of utility owned or leased units. For QFs and IPP units, dispatch and scheduling would depend on contract terms with the local utility. Dispatchable third-party generators would likely be treated the same as utility sources if they demonstrate adequate reliability and availability and if unit dispatch is technically feasible. Nondispatchable third-party generators would not be subject to utility control, except as needed to preserve the stability and reliability of the system. Under this scenario, it is likely that IPPs will be dispatchable under contracts, because their options to sell power to other customers is limited. Emergency curtailments of backup service for third-party generators would be allocated according to State regulated curtailment policies.

Under scenario 1 local utilities would have the responsibility for planning and developing overall generation, transmission, and distribution requirements for the system based on their projections of future electricity supply and demand. These planning efforts most likely would be coordinated with other regional utilities and overseen by State regulatory agencies as part of the preapproval process for new plants. Regulated utilities would retain the obligation to provide adequate and reliable service for current and future needs under this and other scenarios.

In preparing generating capacity expansion plans, utilities will consider various options for securing power supplies, including potential QF sources, and bulk power purchases from other utilities and IPPs, as well as conservation and load management strategies.[21] State authorities would generally approve utilities' generation expansion plans through the certification and preapproval process. QFs, IPPs, and self-generators would plan and build capacity based on their own perceptions of need and profitability. As eligibility requirements are tightened and avoided cost prices are lowered, sponsors might tend to abandon some of the more expensive QF projects currently planned. It is unlikely that any IPP project would go forward without a firm contract with a utility for its power output. Third-party power producers will likely be more successful in areas with low reserve generating capacity margins than in those areas with substantial amounts of existing utility generating reserves or low production costs.

Local and regional utilities would plan and develop transmission system additions subject to regulatory approval. The pressures for increased access to transmission services to accommodate bulk power sales can be expected to continue. State and Federal initiatives toward more flexible transmission pricing may encourage some additional upgrading and expansion of transmission systems. The potential for delays and controversy attendant with proposals for the siting and construction of new transmission lines can be expected to continue. Planning and building distribution system additions would remain the responsibility of the local utility with regulatory approval.

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[19] There are about 150 utility control centers in the United States. Some centers oversee the operations of individual utilities, others govern the operations of participating utilities over a region established through coordination agreements or power pools. See chs. 4 and 5 of this report for more on control area responsibilities.

[20] Under PURPA, utilities are required to interconnect with small power producers and QFs, and cannot impose unreasonable technical requirements to discourage access.

[21] Over half of the States either require utilities to engage in least-cost planning for future electricity needs or are developing such requirements. David Berry, "Least-cost Planning and Utility Regulation," *Public Utilities Fortnightly*, Mar. 17, 1988, pp. 9-15.

SCENARIO 2

Expanding Transmission Access and Competition Within the Existing Institutional Structure

Scenario 2 would preserve most of the electric power industry's existing structure and regulatory framework, but would expand competition in the generation sector more than scenario 1 or the status quo. Scenario 2 would increase the number of potential bulk power sellers by modifying some of the size, technology, fuel, and ownership limitations for QFs under PURPA. This could largely be accomplished by changes in regulations, but eliminating all restrictions on utility ownership would likely require legislation.[22] At the same time, the ranks of prospective buyers would be enlarged by amending the transmission access provisions of the Federal Power Act to authorize FERC to issue transmission access orders under a broad public interest standard.[23] These legislative changes would increase opportunities for both wholesale and retail wheeling. Utilities and large industrial retail customers could purchase electricity "off system" from traditional and nontraditional power suppliers and have it delivered to them over a more open transmission system.

The principal mechanism for achieving increased competition in scenario 2 is the provision for both wholesale and retail wheeling. If efforts to negotiate voluntary wheeling arrangements failed, any utility (including QFs and IPPs) or a very large retail customer would have legal standing to seek a wheeling order from FERC.[24] There would be a rebuttable assumption that the capacity to wheel exists. The utility denying the wheeling services would bear the burden of proving either a lack of available capacity or that accommodating a proposed wheeling transaction would result in a degradation of service.[25] The utility would be entitled to a reasonable compensation for its transmission services.

In addition to new wheeling authority, Federal and State administrative policies intended to encourage greater competition in bulk power sales within the existing institutional structure and increased access to transmission services would be continued and expanded.

Background

Many industry analysts have argued that the regulated electric power industry would be more economically efficient if more competition were

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[22] PURPA provides that a qualifying facility must be "owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration and small power production facilities)." 16 U.S.C. 796(17)(C) and (18)(B). FERC has solicited public comment on several potential changes to its rules on utility equity ownership of QFs. U.S. Federal Energy Regulatory Commission, Notice of Proposed Rulemaking on Regulations Governing the Public Utility Regulatory Policies Act of 1978, Docket No. RM88-17-000, July 19, 1988, pp. 32-57.

[23] For examples of this approach, see *Electricity's Future: A Special Report by the Electricity Consumers Resource Council*, July 1987. See also, the proposed "Electric Utility Transmission Reform Act of 1985" introduced by Rep. Peter H. Kostmayer in the 99th Congress, H.R. 2231. The bill would have amended secs. 211 and 212 of the Federal Power Act to provide that FERC could issue an order requiring an electric utility to provide transmission services for another electric utility whenever it was found necessary or appropriate in order to: 1) conserve energy, 2) promote the efficient use of facilities and resources, 3) increase competition in the bulk power supply market, or 4) otherwise serve the public interest. The order could be granted on the application of any State commission, or public utility, or by FERC acting on its own motion following notice to affected utilities and an opportunity for a hearing. FERC could order a utility to expand transmission facilities to provide the needed transmission services, but the wheeling party would pay the capital and operating costs involved. The bill used a broad definition of a public utility as "any person, State agency, or Federal agency that sells electric energy" for its new wheeling authority, but otherwise would not expand FERC jurisdiction over these entities. H.R. 2231 expressly banned orders to deliver power to "ultimate" or retail customers. OTA's scenario 2 would extend eligibility for wheeling services to "qualified" power purchasers to allow very large retail customers to obtain wheeling. FERC or the States would establish standards for determining which retail customers would qualify for wheeling.

[24] The issue of what constitutes a very large retail customer would be left to the States. It is assumed that States would limit access to facilities that require 20 to 50 MW or more. For example, a pulp and paper mill might qualify at 20 MW in some States, but in others, facilities might require at least 200 MW (e.g., the power requirements of a large aluminum reduction plant).

[25] In deciding whether to grant a requested wheeling order, FERC could consider all relevant issues including the potential impacts on utilities, captive customers, and system reliability. Thus, it is possible that, if granting a wheeling order to an industrial customer to purchase off system would impose a substantial economic hardship on the utility's remaining customers, FERC could deny the request for transmission access under its "public interest" standard.

allowed in certain segments of the industry.[26] Among the benefits of competition they cite are: better use of generation and transmission resources, a more flexible and secure power supply, increased efficiencies in utility operations, and lower prices to consumers over the long-term. In addition, utility ratepayers would have less exposure to the risks of construction cost overruns and poor plant performance as these risks would be shifted more explicitly to the shareholders of nonutility generators. A further benefit of allowing limited competition and more wheeling would be a growth in the information and experience available to assist policymakers in evaluating the technical and institutional feasibility of proposals for broader competition and economic deregulation of electric power.

Proponents note that changes in generation and transmission technologies have diminished some of the so-called natural monopoly characteristics of the electric power industry allowing workable competition to exist as a supplement to regulation. Smaller generating units are now in many cases cost-competitive with large baseload plants and have shorter lead-times. Increased interconnections and higher voltage transmission lines have made regional coordination of utility operations more feasible. With these developments, some analysts see the subregional, insulated, vertically integrated utility as fast becoming an outmoded and economically inefficient entity. In their view, an industry structure dominated by such entities: inhibits cost-savings that could be achieved with greater coordination and bulk power trades between interconnected systems; makes cooperative agreements and power pooling arrangements difficult to establish; provides unequal access to the benefits of coordination and power pools among buyers and sellers; and allows the owners of transmission lines to exercise monopoly power over their sections of the interconnected systems.[27]

The entrance of small power producers and cogenerators into the generation market under the aegis of PURPA has yielded some benefits, but it also has imposed additional operating uncertainties and costs on electric utilities.[28] Expanding the PURPA model is one mechanism for introducing limited competition into the regulated generating sector. A major advantage of this approach is that "smaller increments of increased competition can yield efficiency gains and resolve uncertainties without radically altering present institutional arrangements and risking a costly mistake."[29] At the same time, changes in the criteria for QFs would reduce what some view as inherent market distortions created by PURPA's limitation to small power producers and nonutility firms.

Federal authority to issue wheeling orders rests primarily on three sources:

1. antitrust law (as a remedy for anti-competitive or monopolistic behavior),
2. the licensing power under the Atomic Energy Act, and
3. sections 211 and 212 of the Federal Power Act, as amended by PURPA.[30]

Wheeling orders under antitrust law are rare, and even if a plaintiff is successful, it may take years to work out acceptable arrangements. Wheeling conditions imposed on licensees of nuclear power plants by the Nuclear Regulatory Commission (NRC) and its predecessor, the Atomic Energy Commission have been a major source for guaranteeing transmission access for requirements customers. With no new nuclear power plants on order, additional NRC wheeling orders as part of licensing conditions will be rare. It is possible that NRC might modify some existing licensing obligations, however.[31] Section 211 wheeling orders have been effectively precluded by the heavy burden of proof placed on applicants and the restrictive findings that must be made before an order can be issued. For example, among other things, section 211 requires a finding that existing competitive relationships, such as existing power sales arrangements, not be disturbed.[32] Other difficulties with existing FERC wheeling authority include: the fact that each wheeling application is considered separately; uncertainty over whether QFs and IPPs are included under the broad definition of a utility as any entity that generates power for sale; prohibition on retail wheeling; and Federal court decisions and FERC informal opinions that the 1978 PURPA wheeling provisions narrowed whatever inherent authority may have existed under the Federal Power Act to order wheeling to promote competition.[33]

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[26] See ELCON, *Electricity's Future*, supra note 23; William A. Brownell, "Electric Utility Deregulation: Analyzing the Prospects for Competitive Generation," *Annual Review of Energy 1984*, pp. 229-262; and F. Paul Bland, "Problems of Price and Transportation: Two Proposals To Encourage Competition From Alternative Energy Sources," 10 *Harvard Environmental Law Review* 345 (1986).

[27] William A. Brownell, "Electric Utility Deregulation: Analyzing the Prospects for Competitive Generation," *Annual Review of Energy 1984*, pp. 229-262.

[28] Id., pp. 254-255.

[29] Id., p. 253.

[30] 16 U.S.C. 824j and 824k. See discussion in ch. 2 of this report.

A fourth possible source of wheeling authority is FERC's ability to "condition" its approval of some desired action on the petitioner's acceptance of certain specified requirements. This conditional authority is inherent in FERC's regulatory and policy responsibilities under the Federal Power Act and other laws.[34]

Implementation

Scenario 2 would be implemented through combined Federal and State efforts. Federal legislation would be required to amend PURPA, the Federal Power Act, and PUHCA. State legislation or regulatory action would be needed to implement the changes in Federal PURPA rules.

Changes in PURPA Requirements. Selected changes in the PURPA eligibility standards for qualifying cogenerators and small power producers would increase the ranks of potential competitors in bulk power markets.[35] PURPA vests with FERC the responsibility for establishing technical requirements for qualifying facility status, and most of these initiatives could be accomplished through changes in FERC regulations. Modifications have been suggested to the standards on the unit size, technologies, fuel types, and utility equity participation.

Size: FERC rules limit small power producers to no more than 80MW for PURPA eligibility. There is a statutory limit of 30MW for exemption from State and Federal utility regulation (including regulation under PUHCA). Under scenario 2, the size cap for small power producers would be raised, for example, to 165 MW as proposed by a former FERC chairman.[36] There are no size or fuel limits on cogenerators, because they are not primarily in the business of generating and selling electricity.

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[31] Ohio Edison has asked NRC to revise the wheeling obligations included in the license for its Perry Nuclear plant. The license requires Ohio Edison to wheel cheaper coal-fired power from southern Ohio to 21 municipal distributors in northeast Ohio. Ohio Edison has argued that the wheeling requirements should be dropped because the municipals no longer want to purchase the more expensive Perry nuclear power. "Metzenbaum, Public Power Fight Ohio Edison Wheeling Request to NRC," *Energy Daily*, Apr. 4, 1988, pp. 1-2. Wheeling issues could also be raised before NRC in reviews of license assignments in mergers and acquisitions.

[32] 16 U.S.C. 824j(c)(i). See analysis of Federal wheeling authority in Alvin Kaufman, Carl Behrens, Donald Dulchinos, Larry B. Parker, and Robert D. Poling, *Wheeling in the Electric Utility Industry*, Report No. 87-289 ENR (Washington, DC: Congressional Research Service, Feb. 12, 1987).

[33] See Kaufman et al., id. Similar conclusions were reached in Harvey L. Reiter, "Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation Under the Federal Power and Natural Gas Acts," 18 *Land and Water Law Review* 1-80, 1983; National Regulatory Research Institute, *Non-Technical Impediments to Power Transfers* (Columbus, OH: National Regulatory Research Institute, September 1987); and Bland, supra note 26.

[34] The "wheeling in" and "wheeling out" proposals in the notices of proposed rulemaking would be based on FERC's conditional authority. See note 57 infra. See also the discussion of FERC's authority in ch. 2.

[35] FERC regulations define a small power producer as a facility that produces less than 80 MW of electric power at the same site through use of biomass; waste materials; geothermal energy; or renewable resources such as wind, solar and hydroelectric resources (up to 25 percent of total energy input to QF may be oil, natural gas, or coal). 18 CFR 292.204(1988). FERC defines a cogeneration facility as "equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy." 18 CFR 292.202(c) (1988). To be a qualified facility, the small power production facility or cogeneration facility cannot be owned by a person or entity "primarily engaged in the generation or sale of electric power" (other than the power produced from the qualifying facility). 18 CFR 292.206 (1988).

[36] See Hearings Before the House Subcommittee on Energy Conservation & Power on H.R. 2992 and H.R. 2876 (1981). H.R. 2876 would have increased QF size cap from 80 to 165 MW and eliminated 30MW limit exemptions from Federal and State utility regulation. Legislation in the Senate was introduced in 1982 (S. 1885) and hearings were held. Hearings on S. 1885 before the Senate Committee on Energy and Natural Resources, Apr. 19, 1982. The rationale for this size limit is that it would allow larger QF plants but would be less than some larger utility or IPP planned modular power plants. Legislation in 1981 would have lifted overall size limits to 165 MW.

Utility Equity Participation: Legislation would probably be required to allow full equity participation in QFs by utilities and would be controversial.[37] FERC rules interpreting PURPA have allowed utility equity participation of less than 50 percent.[38] Many utility subsidiaries are active in building QF plants, but they must do so as part of a joint venture with another nonutility firm. Under this scenario, unregulated utility subsidiaries would be able to build and own generating units outside their own service territories and sell power at PURPA avoided cost rates. FERC has solicited comments on how they might amend the existing equity ownership rules to expand utility participation in QFs.[39]

Fuel: Qualifying small power producers are limited to those that produce electricity through use of biomass, waste materials, geothermal energy, or renewable resources such as wind, solar, and hydroelectric resources. They may use oil, natural gas, or coal for up to 25 percent of their total energy input.

Technology: FERC rules require that to qualify, energy use by a cogenerator must be sequential and must meet minimum efficiency standards in thermal output. Sequential use means that the rejected heat from a power production or heating process is used in another power production or heating process. This cascading use of energy in sequential processes gives rise to the energy conserving characteristics of cogeneration.[40] Some new technologies, such as extraction turbines, do not use sequential steam to generate large amounts of power. Modifications to the technology requirements might allow additional facilities to qualify.

Operating and Efficiency Standards: FERC regulations impose different efficiency and operating standards on QF units depending on the type of fuel used. New cogeneration facilities using natural gas or oil must satisfy minimum efficiency levels intended to ensure efficiency superior to conventional utility facilities.[41] No such restrictions are imposed on waste plants or coal plants.

Easing of the above PURPA standards for QF eligibility would increase both the number and diversity of participants in bulk power markets and, combined with increased access to transmission service, would broaden the range of purchase options available to utilities and large retail customers. For those customers either unable or unwilling to assume the risks of purchasing power off system, the local utility would maintain a service obligation to either construct or acquire needed capacity to serve their power supply needs.

Revised PURPA eligibility standards could bring some IPP projects under the QF purchase obligations of utilities. At the same time, with greater variety and more competition among alternative sources, the purchasing utility's avoided costs might be driven down, thus lowering required QF payments. IPP and QF projects could use their access to the transmission system to contract with more distant utilities offering more attractive avoided cost payments. IPPs not meeting QF status requirements would still be able to seek mandatory transmission access to move their power.

Transmission Access and Wheeling—Scenario 2 involves two distinct kinds of wheeling to promote greater competition:

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[37] H.R. 2876 would also have eliminated the utility ownership restriction from the definition of qualifying cogenerators and small power producers. Lifting the utility ownership cap was strongly opposed by State regulators and QF developers. See Hearings on H.R. 2992 and H.R. 2876, supra note 36.

[38] 18 CFR 292.206 (1988).

[39] See Notice of Proposed Rulemaking on Regulations Governing the Public Utility Regulatory Policies Act of 1978, Docket No. RM88-17-000, July 29, 1988.

[40] The requirement of sequential use of energy was added by FERC in its technical definition of cogeneration and is not found in PURPA. The sequential use requirement was viewed as critical even though not statutory. See discussion in Pfeffer, Lindsay & Associates, Inc., *Emerging Policy Issues in PURPA Implementation: An Examination of Policy Issues Related to Federal and State Efforts to Encourage Development of Cogeneration and Small Power Production Under Title II of PURPA*, March 1986, prepared for the U.S. Department of Energy, Office of Coal & Electricity Policy, ch. 11.

[41] Under the Power Plant and Industrial Fuel Use Act of 1978, utilities were largely precluded from building new plants burning oil or natural gas without a special exemption, because these were believed at the time to be scarce fuels. In 1987 Congress repealed the act's fuel restrictions for new utility baseload plants.

1. *wholesale wheeling*—providing transmission services to utilities and nonutility generators for the sale of power for resale (mostly involving sales to utilities); and
2. *retail wheeling*—transmitting power from other generators (utilities, QFs, IPPs) to ultimate consumers, which would also allow "self-service" wheeling among facilities owned by a QF or a self-generator.

Expanded transmission access under scenario 2 would increase the market access of both potential buyers and sellers of electric power and lessen the dominance of the utilities controlling the transmission grids.

Scenario 2 would amend the Federal Power Act to change the definition of those eligible to seek wheeling orders and modify the process through which FERC can order wheeling.[42] The restrictive findings required by existing law, which effectively preclude issuance of wheeling orders in most cases, would be replaced by a more flexible "public interest standard." If efforts to negotiate voluntary wheeling arrangements failed, any utility (including QFs and IPPs) or large retail customer would have legal standing to seek a wheeling order from FERC. There would be a rebuttable assumption that the capacity to wheel exists and any utility denying wheeling services would bear the burden of proof of showing that there is either a lack of capacity or a degradation of service that would result from the proposed wheeling transaction. The wheeling utility would be entitled to a reasonable compensation for its transmission services.

In deciding whether to grant a requested wheeling order, FERC could consider all relevant issues including potential impacts on utilities, captive customers, and system reliability. Thus, it is possible that, if a wheeling order allowing an industrial customer to purchase off-system[43] would impose a substantial economic hardship on the utility's remaining customers, FERC could deny the request for transmission access under a public interest standard. (The customer, of course, would always retain the option of self-generation, which would still leave the utility with the same problem of recovering its investment from a smaller pool of ratepayers.) Providing retail customers with access to transmission would provide them with a bargaining tool in seeking to negotiate rate concessions from their retail supplier.

The principal constraints on a customer purchasing off-system under scenario 2 would be the availability of transmission capacity, and any specific contractual provisions with the existing utility supplier on minimum take and termination notice conditions. Arrangements for backup or standby power supplies would have to be negotiated with the host utility, perhaps with review by appropriate regulatory authorities.[44] In some cases the customer would have to negotiate contracts for provision of unbundled control area services provided by the local utility.

Industrial customers going off-system for their power needs would have to negotiate some stand-by or maintenance service arrangement with their native utilities if they were to expect any sort of service obligation. They may also have to negotiate some provisions for later reconnection to local utility service if State regulations do not already provide for this. The contracts between large retail customers and alternative suppliers would likely be more detailed and complex than their previous agreements with a host utility. Many of the services that had been supplied as part of traditional electric power service would now have to be contracted for specifically. Contracts that involve wheeling agreements with third parties will also require more stringent delineations of technical and operating specifications and responsibilities.

Scenario 2 also would encourage the development of new initiatives to provide greater economic incentives to utilities to wheel voluntarily. FERC could, for example, establish affirmative guidelines for the approval of transmission agreements that might encourage wheeling, such as allowing more flexible pricing of transmission services, requiring compensation of other affected parties (such as other utilities experiencing unintended flows or parallel path problems), permitting auctioning of transmission services, establishing strict timetables for negotiating transmission agreements, and expediting their own review of transmission rates and agreements.[45] FERC might also cooperate in providing guidance and technical assistance to State regulators in pricing and contracting procedures for unbundled transmission and control services.

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[42] See the ELCON proposal and Kostmayer bill, supra note 23. The Federal Power Act defines an electric utility as any entity that generates electric power for resale—some have questioned whether that definition brings QFs and IPPs within the class of parties with standing to seek mandatory transmission orders under existing law. The proposals would also extend standing to FERC, State agencies, Federal power agencies, and large power consumers/purchasers.

[43] "Off system" refers to purchases from a power supplier other than the native or host utility currently serving the industrial customer.

[44] Some States already require utilities to provide backup services at nondiscriminatory rates.

State Initiatives. Because States have the primary responsibility for implementing PURPA under guidelines established by FERC, the States would have to revise their rules and procedures to accommodate the expanded eligibility for QF status. States would have the lead role in implementing changes that permit large retail customers to purchase off system in intrastate transactions. Federal law would not preempt any State laws that characterize an IPP, self-generator, or QF engaged in retail sales as a public utility subject to regulation. States might require instate utilities to wheel power from other instate utilities and nonutility generators to large retail customers.

It is possible that the existing balance between State and Federal regulation could be maintained somewhat if Federal legislation expressly allowed delegation to the States of the authority to implement intrastate retail wheeling under FERC guidelines. State involvement might also be the most politically effective means of implementing retail wheeling because of the substantial equity and fairness considerations involved in weighing the interests of large customers in wheeling power against both the economic impacts on the local utility and the interests of other customers Placing the decision-making responsibility in State hands would move the process closer to the parties that potentially would be most affected by the order.

System Operations and Planning

System reliability and coordination remains the responsibility of the local control center as in scenario 1. Operating requirements for QFs and IPPs would be specified in contracts. System operations would likely be affected more than in scenario 1 as there would be a need to accommodate a greater diversity of generating sources and delivery points.

Dispatch, maintenance, and unit loading operations and procedures would be similar to scenario 1, except that loading and dispatch of transmission accessors not subject to direct utility control would be determined by contracts among the generator, its customers, and the wheeling utility. The wheeling utility would have to adjust its operations to counter any increased uncertainty created by having nondispatchable generators on the system. (Of course, the wheeling utility could impose reasonable technical conditions and charges on the nondispatchable generators and their customers to provide this service.)

Emergency curtailments of service would be allocated according to State-regulated curtailment policies and contracts (same as in scenario 1). For outages of nonutility wheeled power, curtailment and backup power would be based on standby service contracts with the local utility.

Planning and developing generating capacity would be very similar to scenario 1. Under revised PURPA standards, a broader range of facilities would be eligible for QF status, and State law might require utilities to consider QFs as potential components of their capacity expansion plans. It is likely that much more QF and IPP capacity would be built under scenario 2 than under scenario 1. As the amount of nonutility generation grows, States or regional utility groups may wish to provide for direct participation by nonutility generators in the planning process.

Planning for transmission additions would be similar to scenario 1 except that State regulators may require utilities to include provisions for adequate transmission capacity for wheeling services in

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[45] Recent examples of these initiatives include the Western States Power Pool experiment, FERC authorization for Baltimore Gas & Electric to auction off its unneeded capacity on the PJM power pool, and approval of a flexible transmission pricing arrangement between Pacific Gas & Electric and the Turlock Irrigation District, see "PG&E Offers 'New Approach' To Pricing Transmission Services," *The Energy Daily*, Apr. 5, 1988, p. 1.

Photo credit: Dominion Resources, Inc.

Operator at the controls of a power plant

system planning. There is a possibility that some nonutility entities might build private transmission lines, but they would have no eminent domain authority and an uncertain regulatory status. FERC might order a utility to upgrade or expand its transmission facilities to implement a public interest wheeling order. States might also require utilities to expand transmission capacity to accommodate competitive sources.

Distribution additions would be the responsibility of the local utility (same as in scenario 1).

Conservation and load management plans would be developed by the local utility with oversight by State authorities. State regulators may require utilities to include consideration of savings from conservation and load management strategies as part of their least-cost planning efforts as in scenario 1.

SCENARIO 3

Competition for New Bulk Power Supplies

Scenario 3 would create an institutional and regulatory structure to support all source competition for new electricity supplies. Bulk power prices would be established through reliance on competitive market forces rather than cost-based regulation. The overall structure of regulated utilities would be maintained, but limited competition for new capacity needs would be introduced in the generation sector. The present electric power industry structure would be expanded by the entry of IPPs and unregulated utility subsidiaries, divisions, and/or spinoffs created to build and operate new generating facilities and to sell power in competitive markets. The numbers of competing buyers and sellers of electricity would greatly increase, as would the number of entities seeking access to the transmission grid.[46]

Under scenario 3, once a need for new power supplies has been certified by the appropriate regulatory authorities, an electric utility would solicit offers for new power supplies from other utilities, nonutility generators, QFs, and its own unregulated generating subsidiaries.[47] Conservation and load management strategies might also be included as competitive options in some State programs.[48] With appropriate safeguards to limit problems of self-dealing and conflict of interest, the unregulated utility subsidiaries could bid for new capacity within their own service territories.[49] Contracts for new electricity supplies would be awarded based on consideration of both price and nonprice factors (e.g., dispatchability, fuel and technology preferences, location, and relative environmental impacts).

Three mechanisms would exist for securing transmission services: 1) voluntary transmission arrangements with wheeling utilities for utilities and retail customers; 2) transmission access preconditions imposed on utility participants in bidding for competitively awarded bulk power contracts; and 3) public interest transmission orders issued by FERC which would be available only to utilities and wholesale power suppliers.

Scenario 3 would effectively create a two-tiered bulk power supply system: new power supplies under a minimally regulated, "workably competitive" market;[50] and existing generation under the current State-Federal scheme of regulated entry and pricing. Existing generating facilities, and transmission and distribution systems would remain regulated. Gradually, however, as old generation plants are replaced, the system would move toward an unregulated market in electric power generation and supply.

Background

Scenario 3 is loosely based on recent suggestions for allowing competition for new electricity sources. These proposals include those of FERC Chairman Martha Hesse,[51] the Keystone Electricity Working Group,[52] and three notices of proposed rulemaking

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[46] Although the numbers of competing suppliers and potential customers are likely to increase as a result of changes in this scenario, it is not at all clear whether the number of generators that win competitive supply contracts will increase significantly. It is conceivable that traditional utilities and large independent power producers would win many of the solicitations and that the need to integrate many new entrants into the bulk power network would be much less than if a large number of small entities won contracts to supply an equivalent quantity of bulk power. We have assumed for purposes of this analysis that competitive solicitations will yield a larger and more diverse mix of generation than under traditional regulation because that result would pose the greatest challenges for bulk power system operation and control.

[47] As used here, competitive "bidding" includes not only a structured auction with sealed or firm bids, but also less structured competitive negotiations where participating vendors might be selected based on an initial solicitation of proposals, such as, for example, the process used by Virginia Power Co. in seeking alternative power supplies described in ch. 5.

[48] Among the mechanisms for including these demand side alternatives are: 1) to require utilities to consider demand side options as part of a least-cost planning before reaching a determination of new supply needs, 2) to allow demand side options to compete directly with supply options in the competitive solicitation, and 3) to hold a separate solicitation for a desired increment of demand side options.

[49] If a utility chose not to participate directly in the bidding, it might compete indirectly by setting a benchmark based on its own estimate of the costs of building the plant itself and recovering the costs under the base as the supplier of last resort.

[50] As yet, FERC has not offered a clear and objective definition of what would constitute a "workably competitive market" under the Federal Power Act. Development of appropriate findings or guidelines for determining whether a workably competitive market existed would be left to FERC under scenario 3 and would be a prerequisite for implementation. A more detailed definition of the term is not needed for purposes of OTA's technical analysis, however.

[51] See, for example, "Talking Points for the Chairman," The Edison Electric Institute, Cincinnati, OH, June 10, 1987; and "Remarks by FERC Chairman Martha O. Hesse," Energy Daily's Annual Utility Conference, Washington, DC, Nov. 6, 1987.

[52] The Keystone Energy Forum is an informal discussion group with members from industry, government, academia, trade associations, and public interest groups. The working group meets periodically on subjects of current interest. The draft proposal ("Keystone Electricity Draft," 1/27/88) was prepared to merge concepts brought out in discussions of the electricity working group of the Keystone Energy Futures Project. Although the group discussions are largely off the record, reports about the draft appeared in the trade press. The electricity working group never reached a consensus on final conclusions or recommendations on transmission access issues. They are currently considering issues related to transmission pricing.

(NOPRs) issued by FERC in March 1988.[53] Scenario 3 is not identical with any of the proposals, however.

Chairman Hesse initially proposed the use of competitive bidding as an alternative to administrative determinations to set QF avoided cost capacity payments under PURPA. According to Chairman Hesse, modifications of existing PURPA rules to allow States to implement all-source competitive bidding on an *optional* basis and to use these results to establish avoided cost rates would also "fit PURPA into an overall electric strategy which will move us toward a more economically efficient industry."[54]

As a further initiative to expand competition, she suggested, some of the regulatory requirements on IPPs could be reduced for any IPP that is not a QF and that sells electric power in areas where it has no service franchises and otherwise lacks significant market power.[55] Eligible IPPs would receive the maximum pricing flexibility under the Federal Power Act's "just and reasonable" standard and would be relieved of certain reporting and accounting obligations because of their lack of market power. Chairman Hesse deferred discussion of transmission access and pricing issues for future FERC action.

The Keystone Group considered, but did not adopt, a draft proposal opening a utility's future bulk power needs to competition among all potential suppliers with the economic and technical capability to develop needed generating capacity. The proposal suggested that existing regulatory and statutory constraints in PURPA and PUHCA on utility ownership of new power supply projects eligible to participate in this new competitive market would be relaxed or eliminated. The existing PURPA administratively determined avoided cost pricing scheme would be replaced; competitive bidding would allow the prices to be paid by distribution utilities for new generation to be set in the marketplace. If independent generators were unable to meet a utility's need for new generating capacity, the utility would function as a "backstop" or a supplier of last resort for whatever remaining need there was for new power supplies. The utility's cost of providing such last-resort capacity would also set an upper limit on what might be paid to independent power suppliers.

Under the Keystone approach, all independent third-party suppliers would have guaranteed access to transmission service on reasonable terms (subject to availability). The draft did not provide much detail on how the access guarantees would work. Transmission access would not be available for retail customers.

In March 1988 FERC formally advanced Chairman Hesse's suggestions for greater reliance on "workably competitive markets" by issuing NOPRs that would:

1. impose additional procedural requirements for determination of avoided costs by State regulators and unregulated utilities,
2. specify acceptable forms of competitive bidding for new power supplies that could be used by States or unregulated utilities in setting avoided costs under PURPA, and
3. establish IPPs as a new category of power suppliers without market power that would be exempted from many of FERC's reporting and regulatory requirements otherwise imposed on electric utilities.

The NOPRs invited comment on two changes involving transmission. The avoided cost NOPR asked whether QFs should be allowed to construct and own transmission lines and interconnection facilities to transport their own power to purchasing utilities without losing their QF exemption from Federal and State regulation as a public utility. FERC also requested comments on how to deal with situations where a QF wishes to provide wheeling services for others over its transmission lines.[56] The competitive bidding NOPR asked for comments on imposing "wheeling in" and "wheeling out" conditions on utilities participating in bidding programs.[57]

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[53] U.S. Department of Energy, Federal Energy Regulatory Commission, Notice of Proposed Rulemaking on Regulations Governing Bidding Programs (18 CFR Parts 35 and 293), Docket No. RM88-5-000, Mar. 16, 1988, very brief summary published at 53 Fed. Reg. 9324, Mar. 22, 1988; Notice of Proposed Rulemaking on Regulations Governing Independent Power Producers (18 CFR Parts 38 and 382), Docket No. RM88-4-000, Mar. 16, 1988, very brief summary published at 53 Fed. Reg. 9327, Mar. 22, 1988; and Notice of Proposed Rulemaking on Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities (18 CFR Part 292), Docket No. RM88-6-000, Mar. 16, 1988, very brief summary published at 53 Fed. Reg. 9331, Mar. 22, 1988.

[54] Hesse, supra note 51, p. 3. One of the basic overall principles cited in support of her proposal was "The degree of regulation should reflect the degree of market power. Workably competitive markets should be allowed to operate with as little regulatory interference as possible." Id., at p. 4.

[55] The rationale for special treatment for this class of IPPs is presented in a FERC document, "Summary of Current Staff Proposal on PURPA-Related Issues," Sept. 11, 1987, pp. 16-19.

OTA's scenario 3, like the previous proposals, would open up competition for new bulk power supplies. Unlike the Hesse proposals and the FERC NOPRs, the use of competitive procurement methods would not be optional. Scenario 3 also does not require creation of special regulatory exemptions for IPPs. Scenario 3 would condition participation in competitive bidding on agreements to provide transmission access to other bidders—somewhat similar to the wheeling mechanisms described by FERC. Unlike the other proposals however, Scenario 3 would include mandatory transmission access for wholesale bulk power sales under a public interest standard similar to that in Scenario 2 and would clearly require congressional action.[58]

Implementation

Conceivably, scenario 3 could be partially accomplished through administrative actions by FERC. New rules could require States and utilities to use competitive procedures for establishing avoided cost prices for qualifying facilities under PURPA, although this may require a strained interpretation of PURPA and the Federal Power Act. (FERC proposed making competitive bidding optional for State PURPA implementation.) FERC might also formally accept market-based pricing for bulk power sales under its jurisdiction in regions where it found at least a presumption of a workably competitive market. Some observers have concluded that FERC has effectively deregulated many bulk power sales by accepting negotiated arrangements without much inquiry.

Under scenario 3, legislation would be required to expand FERC authority to order wheeling for wholesale transactions among utilities and to assure transmission access for new bulk power contracts. Changes would probably be needed in PUHCA to allow utility subsidiaries and other companies to compete as unregulated entities without coming under the more restrictive provisions of that act.

Many States would require legislation to authorize reliance on market-based mechanisms to set prices for new power sources. Legislation may be needed to vest adequate authority in public utility commissions to oversee and enforce competitive solicitations for new power supplies. A number of States including Connecticut, Massachusetts, Maine, New York, and Virginia, have already sanctioned competitive solicitations as a means of obtaining alternative electricity supplies at the lowest competitive costs. These competitive bidding processes do not, however, necessarily reflect an explicit State policy shift in favor of creating a fully competitive generating sector to replace traditional utility price regulation. Utilities can still build and receive cost of service treatment for new capacity in these States.

Regulators would become more extensively involved in approving determinations of need and in resolving disputes over contract awards under this scenario. The analytical capabilities of State commissions may need to be enhanced and expanded with additional funding and staff. It is presumed that under State competitive bidding programs, considerations of competitiveness and prudence would be addressed before the contracts were approved. Competitively established wholesale power prices would then be passed through to retail customers of the distribution utilities with only limited opportunity for change by State regulators.[59] In some instances regulators may reassert some control over bulk power costs by reexamining the prudence of contract rates and conditions in the context of retail ratesetting and other proceedings. State regulators might disallow full recovery of the purchased power costs if the utility's actions in selecting or negotiating the contract were found to be imprudent (e.g., if cheaper power were available elsewhere). The extent of State agency jurisdiction to review the retail impacts of wholesale contracts has been cast into doubt by a recent U.S. Supreme Court decision.

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[56] Docket No. RM88-6-000, supra note 53, pp. 85-95.

[57] Docket No. RM88-5-000, supra note 53, pp. 87-91. "Wheeling in" would require a utility wishing to bid on the capacity needs of another utility to agree to provide firm transmission services to the purchasing utility for successful bidders that are located within the bidding utilities service territory or that can reach one of its interconnection points. "Wheeling out" would require a utility wishing to bid to supply its own capacity needs to provide firm transmission services to the border of its service area to unsuccessful bidders that wished to sell to another wholesale purchaser. Both forms of wheeling would be subject to "reliability and economic dispatch considerations"

[58] Some critics of the FERC competitive bidding and IPP NOPRs have argued that these actions also should be placed before Congress either because FERC lacks the explicit authority to require them and/or because they raise such significant national policy issues that they are more appropriate for legislative action. FERC Commissioner Charles A. Trabandt is one of the most vocal proponents of the latter view.

The ability of State regulators to examine the prudence of wholesale supply contracts in setting retail rates and approving supply plans was assumed in the development of this scenario. This assumption of effective State review of competitive contracts has been undercut by the U.S. Supreme Court's decision in *Mississippi Power & Light Co.* v. *Mississippi ex. rel. Moore, Attorney General of Mississippi* involving the dispute over the Grand Gulf nuclear plant.[60] The Court held that FERC authority over wholesale sales preempted any State commission inquiry into the prudence of the management decisions concerning the underlying power supply contract between Mississippi Power & Light, a subsidiary of Middle South Utilities, a public utility holding company, and another of the holding company's subsidiaries. Because of this preemption, the States were required to pass through the wholesale rates to their customers; all prudence issues would have to be raised by States and consumers in hearings before FERC. If extended beyond the facts of the Grand Gulf case, the Court's decision could require Federal legislation to implement scenario 3 in a form that assured effective State oversight of a utility's competitive supply arrangements.[61] Alternatively, new procedures and authority and expanded resources would be needed at FERC to provide an equivalent Federal role.

In scenario 3, State and Federal authorities would no longer *directly* control entrance into the generation sector (through certification of capacity need), nor would they set wholesale prices for power from new generating facilities. Instead, a system of competitive-bidding or negotiated contracts would establish competitive market-based rates. These competitively established bulk power prices would then be passed through to retail customers of the distribution utilities. This approach may require a preliminary finding that a workably competitive situation exists for new power transactions and continuing market oversight by State and or Federal regulators. Most probably, regulators would be more extensively involved in approving a utility's assessment of capacity needs and in resolving disputes over contract awards.

Prices for "old" power supplies would remain under existing cost-based regulation. New competitive power supply prices could reflect levels of service and other non-price factors. Prices for transmission services would continue to be regulated by FERC. Greater reliance on transmission services may increase pressure for transmission pricing based on actual measured cost of service with allowances for non-price factors.[62] Alternatively, there will also be pressure from transmission owners and others to allow more flexible and value-based transmission pricing.

Under scenario 3 QFs and IPPs would be able to compete to sell wholesale power to utilities. They would not have access to the transmission system to sell power directly to retail purchasers, however, except to the extent that utilities controlling the grid voluntarily agreed to provide wheeling services.

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[59] Under existing law, FERC has jurisdiction over the prices for most wholesale power sales. PURPA exempted purchases of QF power from FERC price regulation. States have jurisdiction over utilities resource planning and construction and retail rates. States are generally required to pass through purchased power costs at FERC approved prices under the "filed rate doctrine." Without a change in PURPA or the Federal Power Act, FERC would have to approve contract prices for purchases from utilities and IPPs under a State competitive procurement program. See discussions in ch. 2.

[60] No.86-1970, June 24, 1988.

[61] Questions about the prudence of utility decisions in awarding bulk power contracts could arise later if a utility overestimated future demand and was left with a take or pay contract for unneeded electric power. The central issue would not be the contract price, but whether the utility's initial decision to purchase additional supplies was prudent and whether the full costs should be passed through to ratepayers. Another possible subsequent retail rate issue might arise over a utility's prudence in signing a contract with price escalation clauses that resulted in actual contract prices that exceeded those on which the initial bid was awarded.

[62] Transmission prices are now commonly set in several ways, postage stamp rates, split the difference in savings rate, and others. See National Regulatory Research Institute, *Some Principles for Pricing Wheeled Power* (Columbus, OH: August 1987). Edison Electric Institute, Rate Regulation Department, *Terms and Conditions of Existing Transmission Service Agreements*, 04-85-05, 1985.

Systems Operations and Planning

System reliability and coordination would be maintained as in scenarios 1 and 2 with primary responsibility resting with the local utility and/or control center. Operational requirements for nonutility generators (e.g., QFs and IPPs) would be based on contract terms with the local utility (or wheeling utilities). More formalized agreements would be needed to replace many of the current informal operating arrangements of integrated utilities and power pools as electric power supply functions are increasingly "unbundled."

Dispatch, maintenance, and unit loading schedules for the system would largely be handled by the local utility or control center. Specific dispatch and scheduling responsibilities of nonutility generators and transmission accessors would be negotiated by contracts among the generators, power purchasers, and wheeling utilities as in scenario 2.

Emergency curtailments of generation and transmission services would be dealt with as in scenario 2.

Planning and developing generating capacity additions would primarily be the responsibility of the local utility as in scenario 2. Because the States would require utilities to use a competitive selection process (including consideration of non-price factors) for new power supplies, State regulators would be more heavily involved in overseeing utility demand forecasts and determinations of capacity needs. Independent generators would be free to make their own plans for new construction based in part upon the utilities' needs and in part on their own expectations of profit.

Transmission additions would be planned and built by the public utility transmission company or division with review and approval by regulatory authorities. State rules may require utilities to plan for adequate capacity for instate wheeling of new power supplies and to consider regional transmission needs. As in scenario 2, FERC may order a utility to expand its transmission capacity to provide mandatory wheeling services.

Planning and building additions to the distribution system would remain the responsibility of the local utility.

Conservation and load management planning and implementation would be the responsibility of local utilities as in scenarios 1 and 2. State authorities may require consideration of potential contributions of conservation and load management strategies as part of utilities' least-cost planning and in approving retail rates. State regulators might also allow demand side options to compete directly in the bidding process for capacity additions.[63]

SCENARIO 4

All Source Competition for All Bulk Power Supplies With Generation Segregated From Transmission and Distribution Services

Scenario 4 would restructure the U.S. electric power industry and its regulatory institutions and create a competitive, unregulated generating sector and a structurally separate regulated transmission and distribution sector. Integrated utilities would be required to segregate generation activities, both institutionally and operationally, from transmission and distribution to limit the potential for self-dealing and cross-subsidization. Owners of existing and new generation sources would compete to sell power to regulated transmission and distribution companies. Some transmission companies could also act as power brokers or wholesalers providing bulk power supply planning, purchasing, and delivery services to distribution utilities. Purchasing utilities would be assured access to transmission services for their bulk power needs (capacity permitting).

The scenario would entail substantial rewriting of Federal and State laws governing utility regulation with greater emphasis on authority for overseeing the competitiveness of bulk power markets and regulating transmission services and power brokers. Modifications of the public utility ownership restrictions in the Federal Power Act, PURPA, and

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[63] Regulators in Maine have allowed demand-side management options to compete to provide needed decrements of power capacity. In bidding conducted by Central Maine Power for 100 MW of capacity, 13 of 37 total bids were for demand-side management projects, however these projects represented only 35.6 MW out of more than 1,145 MW offered. On a price basis, the demand side projects averaged 75 percent of the utility's avoided costs, while the supply side offers averaged 97 percent of avoided costs. *Issues Review and Tracking*, Aug. 4, 1988, p. 1.

PUHCA would allow broader participation in generation markets. State regulatory schemes would also have to be overhauled to accommodate this scenario. The scenario could shift the primary locus of utility regulation from States to the Federal Government, but implementing legislation could maintain a balance by giving greater wholesale authority to State regulators. States would regulate the prices, operations, and quality of service of retail distribution companies. Transmission capacity, services, and rates would be subject to mixed Federal and State regulation.

Background

Scenario 4 is derived from proposals that would structurally disaggregate the electric power industry to allow the generating sector to become both more dependent on the discipline of competitive market forces and free from many of the pricing and entry restraints of the existing regulatory system.[64] Under scenario 4, the organizational structure of the electric power industry would begin to resemble that of the natural gas industry where production, interstate transmission, and local distribution are generally under separate ownership (although there are numerous cases of "upstream" and "downstream" integration).

Scenario 4 would open all power supply contracts to competition, unlike Scenario 3, which is limited to new bulk power sources. Because Scenario 4 would be applied industry wide, it would probably involve a transition period of many years to allow a gradual phase-out of rate-of-return regulation, orderly restructuring and divestiture of assets, and renegotiation of existing arrangements.[65]

Radical industry restructuring has some precedent in the recent experience in breaking up AT&T and deregulating much of the telephone industry. On a much smaller scale, several utilities have sought to revamp their internal structures to set up holding companies, split power system functions into separate subsidiaries, and create unregulated competitive generating subsidiaries.[66] But, there is no precedent for radical restructuring and deregulation of an industry similar to electric power that is characterized by long-term investment, heavy fixed costs, an obligation to serve, and which is in a period of excess capacity. The restructuring under scenario 4 raises major questions of public policy and equitable treatment of stockholders and ratepayers in allocating any increased value for existing assets.

As one benefit of removing most price and entry restrictions from the generating sector and replacing them with open competition, "there would be strong, direct incentives for efficiency in construction, and new units would be built by companies that could offer capacity at the lowest life cycle costs."[67] The principal risk would be threats to the reliability and stability of the overall integrated systems arising from lack of or reduced coordination among competing entities. Proponents believe there would also be substantial efficiency gains in the use of all available generating units to meet regional electricity demands. In their view, these efficiency gains would not likely be achieved under the existing structure because of the disincentives to increased bulk power transfers among utility control areas, difficulties in forming power pools, and transmission capacity constraints.

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[64] See for example, Richard J. Pierce, Jr., "A Proposal to Deregulate the Market for Bulk Power," 72 *Virginia Law Rev* 1183 (1986); Aspen Institute, "Electric Utilities: Structure and Regulation," *Energy Policy Forum*, 1986, and William W. Berry, "The Case for Competition in the Electric Utility Industry," 110 *Public Utilities Fortnightly* 13 (1982).

[65] At least one proponent of a similar approach argues that mandatory divestiture and reorganization of the industry by courts and legislatures would not be needed because competitive pressures would force firms to restructure voluntarily through spinoffs, mergers, and acquisitions eventually producing the desired efficient industry structure. This process could, however, take as long as 20 or 30 years. Pierce, supra note 64, p. 1214.

[66] For example, Public Service Company of New Mexico proposed a significant corporate restructuring that would form a holding company, split most generation and transmission assets into a separate competitive subsidiary, and sell power under long-term contracts to a distribution subsidiary and its wholesale customers. The company dropped its proposal in mid-1988 because of the criticisms raised by some State agencies and the City of Albuquerque, its largest wholesale customer.

[67] William W. Berry, "The Implications of Deregulation for Electric Utilities," Comment for the Reason Foundation Conference on Deregulating Public Utilities, 1987.

Implementation

Scenario 4 would require substantial changes in both Federal and State laws governing the electric power industry. The Federal Power Act's jurisdictional and procedural requirements would be substantially revised to reflect the new institutional structures with greater emphasis on creating effective mechanisms for overseeing the competitiveness of bulk power markets and regulating transmission services and power brokers. PURPA and PUHCA would also require amendment to remove statutory barriers to full participation in the competitive generating sector. This would allow utilities' generating companies to compete outside of their regional territories without coming under the full financial and operational restrictions imposed on regulated utility holding companies. Continuation of PURPA's purchase and sale obligations for alternative energy sources might also require reexamination to determine if they still were effective and/or appropriate under a changed industry structure.

The transmission and distribution segments of the industry would continue to be regulated heavily while generation would be subject only to competitive market forces, regulatory oversight, and antitrust laws. Price and entry regulation for the generation sector would be replaced with competitive markets. Generators would still be subject to environmental, siting, financial, and antitrust requirements imposed by other State and Federal laws under scenario 4 and all others. The States would regulate the prices, operations, and quality of service of retail distribution companies. State regulators would review the power purchase contracts of distribution utilities, but the effectiveness of State programs would be hindered without some mechanism to review the adequacy of competitive market transactions. Transmission capacity, services, and rates would be subject to mixed Federal and State regulation. Under this scenario there is the potential for increased Federal regulation and oversight of bulk power supplies and what were formerly intrasystem transmission arrangements. Implementing legislation could, however, provide for a more balanced Federal-State division of regulatory authority to give States greater control over intrastate activities.

Vertical integration of the electric power industry would be reduced by the separation of utility generating segments from transmission and distribution segments.[68] This could be accomplished by creating new subsidiaries or divisions, or by spinning off a new company and then "selling" the required physical plant and other assets to the new entity.[69] Segregated utility generators, QFs, and IPPs could compete to provide power supplies to transmission-distribution and local distribution companies. Age, performance, and fuels of existing units will affect the competitive strengths of the new generating companies. These competitive differences could eventually lead to a consolidation of the industry.[70]

Under scenario 4 local distribution companies would be primarily responsible for securing adequate power supplies from competing suppliers through contract solicitations and negotiations. Regulated transmission companies would own and operate the transmission facilities and be responsible for planning and building networks with adequate capacity to serve buyers and sellers in a competitive market. Transmission companies would function as regional controllers and dispatchers of generation and provide wheeling services for utilities under regulated rate schedules. They could also act as power brokers or as wholesalers linking independent generators and local distribution utilities.

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[68] Under scenarios 4 and 5, the physical division of integrated utility facilities among the newly disaggregated entities would probably not reflect a clearcut allocation of generation, transmission, and distribution facilities. It is likely that at least a portion of the transmission facilities associated with individual generating stations might be retained by the generating subsidiary. Generators might have to construct their own transmission facilities to move power to the point of delivery to the transmission or distribution companies. Similarly, transmission and distribution utilities would be able to retain or acquire small scattered generating units that provide essential system support or backup services.

[69] This financial restructuring and redistribution of assets will be a complex and controversial aspect of this scenario for utilities, shareholders, regulators, and ratepayers alike. If not handled with caution, the transactions could result in a sizable transfer of wealth and assets from the regulated sectors to the unregulated generators. There could be a tremendous incentive for owners of low cost older plants to move them as quickly as possible into the unregulated market so as to capture a greater profit than would be allowed under regulated historic embedded cost pricing. This could leave a utility's high cost plants in the regulated sector.

[70] See, for example, Joskow and Schmalensee, supra note 1, pp. 212-213.

Generators and distribution companies could seek transmission orders from FERC based on a public interest standard similar to that in scenarios 2 and 3. Unlike scenario 2 there would be no mandatory wheeling for retail customers. It is expected, however, that many generators and transmission companies would sell directly to large retail customers under arrangements for bypass or standby payments to local distribution companies.

Distribution companies under scenario 4 would retain an obligation to serve, that is, to plan for and secure adequate electricity supplies for the needs of their franchise customers. But with little or no generating resources of their own, they would be highly dependent on the willingness of independent suppliers to construct needed capacity and the availability of adequate transmission capacity to move the power. Competing generating companies would be under no legal obligation to build new capacity, but would commit to do so if and when the market price was sufficient to assure them an attractive return. Thus, in the generating sector market price signals would displace the utility's traditional service obligation as the principal mechanism for assuring the availability of adequate and reliable power supplies. The experiences of the numerous independent distribution companies that currently obtain their electricity supplies and transmission services from larger integrated utilities could provide helpful precedents.

Transmission under scenario 4 would begin to assume some of the characteristics of a common carrier, but the transmission entity would retain some discretion over who was eligible to obtain service and would not be required to provide wheeling to retail customers. The transmission company could not impose unreasonable or discriminatory conditions on transmission access. It could, for example, specify minimum operating standards to preserve system reliability and require advance notice and financial commitments to reserve firm transmission capacity.

Independent generating companies and local distribution entities would be linked by these newly created transmission entities, which would serve as regional controllers and dispatchers of generating capacity. In addition to this primary role, transmission utilities could also serve as regional power brokers which would make the market for, and be party to, contracts negotiated between independent generating companies and distribution entities. Transmission companies might also assist in the creation of secondary futures markets as a means of hedging against the added uncertainty associated with a vertically segregated industry.

Under scenario 4, transmission access would be achieved primarily through voluntary negotiations; however, the separate transmission entities would have an obligation to provide adequate transmission capacity to support the industry's new competitive structure. FERC would also have the authority to order wheeling for customer utilities on a public interest standard if satisfactory voluntary arrangements could not be reached through negotiation. With FERC's endorsement, States might require nondiscriminatory access to transmission services as a precondition for allowing existing regulated generation, transmission, and distribution companies to participate in the new competitive system. Transmission access for retail customers would be kept on a voluntary basis.

Systems Operations and Planning

System reliability and coordination would be the responsibility of the regulated transmission company or transmission-distribution company. The transmission company would take over many of the day-to-day functions of system coordination that are now the responsibility of local utilities and control centers. Operational responsibilities of power suppliers and local distribution companies would be specified in contracts with State and Federal oversight.

Dispatch, unit loading, and maintenance schedules would be administered by the transmission utility under various contracts between power suppliers and: 1) regulated transmission companies, 2) regulated distribution companies, and/or 3) retail customers. Dispatchable generators would be controlled by the transmission company and compensated for their services according to contract terms.

Emergency curtailments for retail customers served by local distribution companies would be allocated according to State-regulated curtailment policies. For other customers, curtailments would be specified in contracts with the transmission and generation suppliers. Curtailment of transmission services will be based on contractual terms, State and Federal regulation, and system reliability considerations.

Generating Capacity Additions: Future electric supply requirements would be determined by the local distribution company through its planning processes with State oversight. Competition for supply contracts would be open to all generating sources, as in scenario 3. Independent generators would plan and build new plants based on utilities' indications of need and their own strategic plans and profit expectations. Transmission utilities could also contract for generating capacity to aid in preserving system reliability and to allow them to serve as power brokers subject to State and Federal regulation.

Transmission Additions: The regulated transmission or transmission-distribution companies would have the obligation to provide transmission capacity necessary to support wheeling needs for instate utilities. (This assumes of course that wheeling is economical and that wheeling customers are willing to pay for the additional capacity needs.) States could require transmission capacity planning to include consideration and coordination of regional transmission system needs.

Distribution additions would be the responsibility of the locally regulated distribution utility, with oversight by State authorities—same as in scenario 3.

Conservation and load management programs would be provided by local distribution companies, possibly in conjunction with transmission companies. State regulators could require consideration of potential contributions from load management and conservation strategies as part of the distribution utility's least-cost planning processes in this and other scenarios.

SCENARIO 5

Common Carrier Transmission Services in a Disaggregated, Market-Oriented, Electric Power Industry

Scenario 5 would break up the vertically integrated electric power industry by divesting generation, transmission, and retail distribution segments into separate entities. All customers (both wholesale and retail) would have the option of purchasing power from any willing supplier with the assurance that such power could be delivered under reasonable terms and conditions. Distribution and transmission services would remain tightly regulated, but entry and bulk power pricing in the electric generation segment would primarily be left to market forces.

The competitive generation segment would include formerly regulated utility generation operations, QFs, and IPPs (although such distinctions among power producers would no longer be relevant). Unlike scenario 4, ownership of generating companies would be completely severed from ownership of transmission and distribution companies. The regulated transmission companies would explicitly be required to provide transmission services as a common carrier (i.e., nondiscriminatory service based on approved wheeling tariffs to all parties requesting service) and to provide adequate transmission capacity. Wheeling to retail customers would be available, although as a practical matter it would likely be limited to very large industrial consumers. Federal and State policies might encourage greater aggregation in transmission services to create coordinated large regional transmission systems—either through mergers and acquisitions or through operational agreements among neighboring systems.

Background

Scenario 5 includes many of the key elements of the preceding scenarios including vertical disintegration of industry structure, market-based pricing of generation, and transmission access. Under scenario 5, any generator could sell to any buyer, any buyer could purchase from any seller, and the transmission company would have to wheel the power. Proponents of this radical restructuring of the industry cite a number of technological and public policy reasons for adopting this approach.[71] Chief among them are: the decline of the natural monopoly characteristics of the generating sector; the excess generating capacity in many regions; and the presumably higher social and economic costs to society of "imperfect regulation" compared with "imperfect competition."

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[71] See for example, Philip R. O'Connor, Robert G. Bussa, and Wayne P. Olson, "Competition, Financial Innovation, and Diversity in the Electric Power Industry," *Public Utilities Fortnightly*, Feb. 20, 1986, pp. 17-21; Philip R. O'Connor, "The Transition to Competition in the Electric Power Industry," Illinois Commerce Commission (presented at the American Power Conference, Chicago, IL., Apr. 22, 1985); and Matthew Cohen, Essay: "Efficiency and Competition in the Electric Power Industry," 88 *Yale Law Journal* 1511-1549, June 1979.

The key to having a vigorously competitive and economically efficient electric power industry lies in the evolution of new institutions and arrangements.[72] This is unlikely to be accomplished merely by allowing distribution utilities and others to shop around for the best bulk power deal without first establishing the necessary competitive market environment. Among the changes in industry regulation, operations and structure that would lead to achievement of this scenario are:

- encouraging the regionalization of utility regulation and operations by expanding the use of centralized dispatch of generating capacity within States or regions;
- creating power brokerage and auction markets;
- realigning Federal and State regulatory authority to allow States clear authority in intrastate bulk power and wheeling markets;
- creating federally approved interstate regulatory compacts for governance of central dispatch, auction, and brokerage systems; and
- assuring open and fair access to transmission systems either through mandatory wheeling or through creation of new regional transmission entities.

Implementation

Scenario 5 would require rewriting of existing State and Federal laws and regulations governing electric power generation, transmission, and distribution. Although "deregulated," the competitive generating sector would need continuing oversight to assure the existence of workably competitive markets. In addition, new contractual arrangements and industry practices would have to evolve to assure effective operations under a new disintegrated, market-based industry structure, and to preserve reliability and stability of interconnected electric power systems.

Regulators would approve the transmission company's wheeling tariffs for both utility and nonutility generators. FERC (or perhaps a regional authority) would have the power to issue wheeling orders to facilitate bulk power transfers if satisfactory arrangements could not be made with the transmission company. Wheeling rates would be designed to include adequate signals to assure construction of new transmission facilities. The transmission utility also would have an obligation to plan for and build adequate and reliable transmission capacity to serve regional needs and to accommodate interregional transfers. Wheeling customers could contract for different levels of service (e.g., firm, interruptible).

Bulk power prices would be set through competitive markets and passed through to ratepayers. Power purchases by distribution companies and retail rates would be regulated by State authorities. Retail rates and the need for and prudence of bulk power purchases by distribution companies would be regulated as now by State authorities. Rates charged by transmission companies acting as power brokers and reselling to distribution companies would also be subject to regulatory oversight to assure that there was no cross-subsidization of operations or anticompetitive practices.

This scenario would involve the mobilization and transfer of billions of dollars in utility assets to newly established entities. Because of the complexity of the transactions, it is likely that many years would be required to complete an orderly transition.[73] The essential step in achieving this scenario would be the establishment of a separate and functional common carrier transmission entity. This could be accomplished simply by spinning off the transmission assets and operations of a vertically integrated utility to a new private entity. It could also be accomplished through legislation to create federally chartered and publicly held regional transmission (and dispatch) corporations to acquire all transmission lines and facilities within a designated region.

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[72] See Joskow and Schmalensee, supra note 1, at pp. 104-105, for their "scenario 4" which adopts a similar approach. See also Edison Electric Institute, "Deregulation Issues and Concepts," 1981. The industry structure of scenario 5 resembles that proposed for the utility industry in the United Kingdom after privatization. See ch. 2 box 2-B. The U.S. industry and regulation structure are far more complex than the present government-run British system, so that direct comparisons with the U.K. proposal are of limited value.

[73] A detailed transition plan for achieving this sort of industry has been outlined conceptually by Phillip O'Connor, former Chairman of the Illinois Commerce Commission. O'Connor's 10-step process would gradually transform the industry into a vertically disintegrated structure with market-based pricing of generation evolving in conjunction with regulated transmission and distribution entities. O'Connor, supra note 71.

Systems Operations and Planning

System reliability and coordination would be maintained by the separate, regulated transmission company. The operational responsibilities of power suppliers and local distribution companies would be specified in contracts with the transmission company.

Dispatch, unit loading, and maintenance schedules would be determined by the transmission company in negotiation with generators and governed by contracts as in scenario 4.

Emergency curtailments of electric power and transmission services would be allocated according to contractual arrangements and/or State regulations.

Generating capacity additions would be planned and built by independent generating companies based on their strategic plans, profit expectations, and transmission and distribution utilities' indications of need. Distribution and transmission companies (jointly or separately) would project future demand and determine the desired mix of generating resources to meet those needs before soliciting contract bids from power suppliers.

Transmission additions would be planned and built by the transmission utility which would have an obligation to provide adequate and reliable transmission capacity necessary to supply the wheeling needs of anticipated customers. Regulatory authorities may require consideration and coordination of regional transmission capacity needs in planning.

Distribution additions would be planned and built by the local distribution utility as in scenario 4.

Conservation and load management strategies would be developed by local distribution companies in cooperation with transmission companies and regulatory authorities.

ANALYSIS OF THE SCENARIOS

These scenarios were used by OTA and its contractors in its assessment of the technical and institutional feasibility of expanding competition and opening up transmission access. Chapter 5 looks at the technical aspects of changing the electric power infrastructure to accommodate the scenarios and some cost and performance implications. Chapter 6 examines the regional characteristics of the electric power industry and how they might affect the successful implementation of the scenarios. Finally, chapter 8 examines policy options for resolving some of the technical and institutional problems identified in OTA's analysis.

There are many other possible scenarios that could be used. Selection of these five reflect the best judgment of OTA staff and others about the range of possible future industry structures that may be most useful in testing the technical feasibility of adapting existing bulk power systems to change.

The five OTA scenarios were developed and analyzed for the limited purposes of this assessment. These scenarios are not intended as legislative policy options. They may not be, in some respects, the optimal or most probable policy choices in considering the creation of a new regulatory and institutional framework for the U.S. electric utility industry as a whole.

Many difficult and controversial aspects of making the electric power industry more competitive are not included in OTA's review of the technological feasibility of expanded competition and increased transmission access. We did not conduct an extensive analysis of all the legislative and regulatory changes that would be needed to implement each of the scenarios. For example, we did not analyze in detail the considerations to be addressed in deciding on whether to grant a petition for mandatory transmission access under a revised public interest standard. Nor did we address the very thorny problems of how to divide the assets and liabilities of existing utilities among ratepayers, shareholders, and regulated and unregulated subsidiaries. Issues of national energy policy were also beyond the scope of this study. Therefore, we did not examine in any detail the possible implications of changing PURPA's preference for certain classes of cogenerators and small power producers. OTA's study may, of course, help to identify many of these issues for Congress. The scenarios may also prove a useful tool for analyzing these policy options and responses.

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Chapter 4

Power System Technology

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Chapter 4

Power System Technology

INTRODUCTION

An electric power system is a vast, complex machine composed of a large number of generators, transmission lines, distribution systems, and substations. Although less physically obvious than generators and transmission lines, systems to coordinate the operation and planning are also vital components without which power systems could not function. Coordination systems include monitoring and communication equipment, devices that actually control generators and transmission lines, and engineering models and expertise which specify how to operate generators and transmission lines as well as plan equipment additions.

As discussed in chapter 1, the demands on power systems are changing. Electricity generation is becoming increasingly competitive, with new forms of ownership and control, and some new technologies are being introduced. Both generators and purchasers of power are seeking greater access to transmission. Utilities are pursuing new methods to reduce costs by improving operating efficiency.

Improving operating efficiency, integrating competitive power supplies, and wheeling power require modifications of uncertain technical feasibility and economic merit. Can a power system operate with many separately owned generating companies and power purchasers demanding access? Is there sufficient transfer capacity to accommodate the changes? What will be the impact on reliability and efficiency?

The physical principles of electricity greatly complicate answering the technical questions. Because power flows at nearly the speed of light with virtually no storage of electricity in a system, the supply of power must balance customer demand at every instant. Also, the flow of power on individual transmission lines is difficult to control. Consequently, the performance of all components is highly interrelated. For example, a generator failure instantly alters the power flows on transmission lines, perhaps beyond safe physical limits, while requiring that other generators immediately increase output to meet demand. Due to the highly integrated nature of power systems, answering the technical questions requires examining the overall power system and the role played by each of the major components.

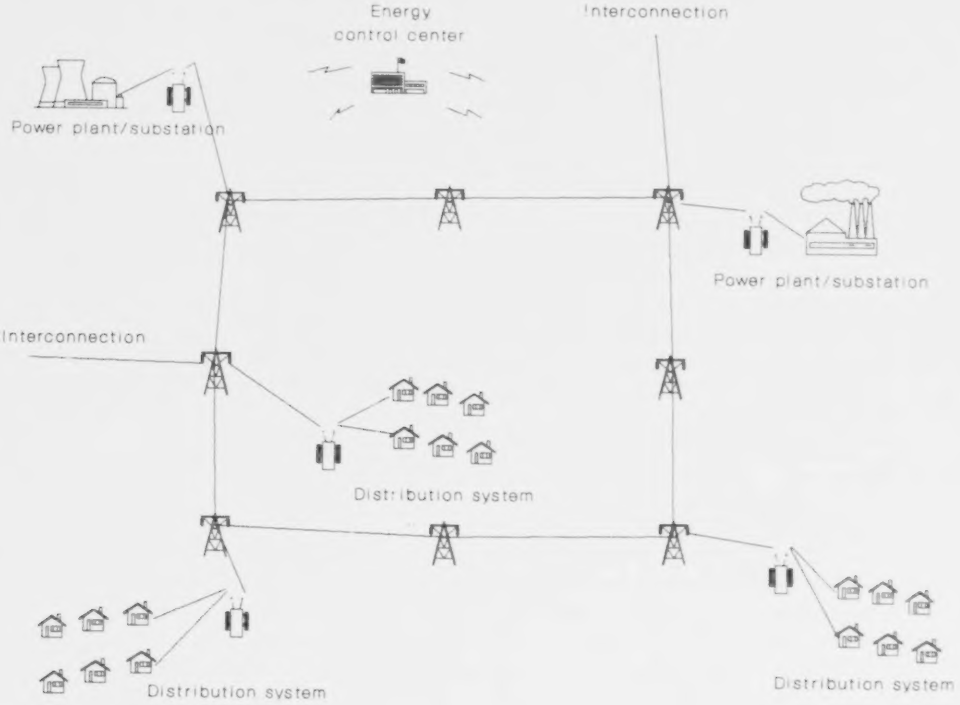
Chapter 4 examines current and future power system technology, and the opportunities to increase transfer capabilities and operating efficiencies of existing systems. The first section discusses the fundamentals of power systems—the equipment that composes the system and their performance requirements. The second section examines the functions involved in coordinating all the individual generators and transmission components into an integrated bulk power system. The last section examines the physics of power transfers, and opportunities to increase transfer capability.

OVERVIEW OF POWER SYSTEM EQUIPMENT

An electric power system is comprised of the major pieces of equipment we commonly associate with the utility industry. This equipment includes *generating units* that produce electricity, *transmission lines* that transport electricity over long distances, *distribution lines* that deliver the electricity to customers, and *substations* that connect the pieces to each other. The *bulk power system* includes the generating plants, transmission lines, and their associated equipment. *Energy control centers* coordinate the operation of the bulk power system components from moment to moment and prepare for the near future. A wide variety of other planning and engineering systems coordinate operating and capacity expansion plans for the longer term. Figure 4-1 shows a simple electric system with two power plants and three distribution systems connected by a transmission network of four transmission lines.

The U.S. power industry uses a variety of fuels and technologies to generate electricity. Nuclear fission, fossil fuels, and falling water are all commonly used to drive *electric generators* which convert mechanical energy into electricity. Conventional generators typically produce 60 cycle/second (Hertz or Hz) alternating-current (AC) electricity with voltages between 12 and 30 kilovolts (kV). The 60 Hz power is generated in three time-varying

Figure 4-1—A Simple Electric System



SOURCE: Office of Technology Assessment, 1989.

sinusoidal patterns, called *phases*. Generating units have *automatic voltage regulators* which control the unit's voltage output and *speed governors* which adjust power output and frequency in response to demand and changing system conditions.

A wide and growing variety of unconventional generation technologies have been developed, too. These include cogeneration, conversion of solar energy to electricity, wind-driven generators, and unconventional fuels such as waste material. The mix of fuels and technologies changes from year to year as new units are built and old units are retired.[1]

A *generation substation* connects generators to transmission lines. To minimize losses over long distances, transmission lines require high voltages, typically between 69 and 765 kV. *Power transformers* at the substations raise the voltage to these high levels for efficient transmission. Substations also house a variety of equipment for monitoring and communication and for controlling and protecting both the transmission and generation facilities. A *power plant* consists of one or more generating units on a site together with a substation.

Transmission lines carry electric energy from the power plants to the distribution systems. Most transmission in the United States consists of overhead AC lines operated at 69 kV or above. Often, lower voltage transmission lines operating at between 23 and 138 kV are termed *sub transmission*, although the distinction depends on the characteristics of the individual utility system and is not uniformly applied.

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[1] See ch. 6 for a breakdown of the mix of generating capacity.

Power actually flows along bundled strands of wire called *conductors*. Conductors are bare metal cables, typically aluminum strands around a steel core. AC transmission lines typically have three individual or paired conductors to carry three-phase power. There are some segments of direct current transmission and underground cables for special applications, although these are less common than overhead AC lines. Figure 4-2 shows a typical transmission line, consisting of a *right-of-way*, *towers* to support the conductors, the conductors themselves attached to the towers by *insulators*, and additional *shield wires* to protect the conductors from lightning.

The width of the right of way and the tower design are determined by the voltage of the line and the need for air insulation to prevent electricity from flashing over (i.e., arcing between a conductor and the ground or the tower). Towers may be made of wood, concrete, steel, or aluminum depending on the number and weight of conductors, the terrain, and the distance between towers. In addition to the weight of the conductors, the towers must be able to support any ice which forms on the lines and the force of wind. Typically, high-voltage lines have numerous heavy conductors, requiring use of metal towers for strength.

Figure 4-2—Transmission Line

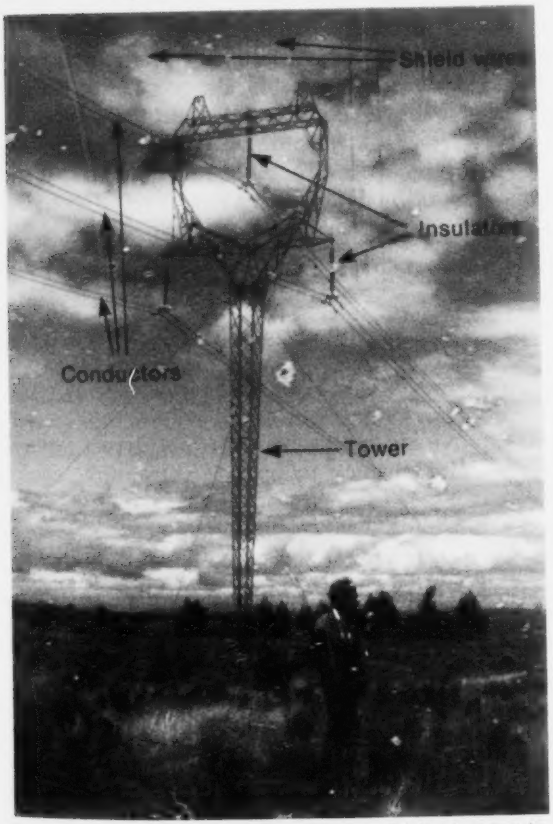

Photo credit: Cassaza, Schultz & Associates, Inc

In addition to the conductors and towers themselves, transmission systems have monitoring, control, and protective devices much like those found in power plant substations. *Transmission substations* house this equipment together with devices used to regulate voltage and power flow on the lines.

An interconnected group of individual transmission lines comprises a *transmission system*. A transmission line connected at both ends to other transmission lines is part of the *grid* or *network*. Transmission lines connected to the grid at only one end, with the other end connected either to a generating plant or customer loads, are called *radial* or *feeder* lines. The transmission system shown in figure 4-1 allows each distribution system to receive power from either of the power plants. Even if one network line is disconnected, each distribution system can still receive power from both generators.

Some very large electric consumers, such as major industrial plants take their power directly from the transmission system, typically at subtransmission voltage levels between 23 and 138 kV. A substation containing metering, protective, and switching apparatus connect these large customers to a transmission line. Most customers, however, receive their electricity from a distribution system.

Distribution systems operate at lower voltages than the transmission system, typically under 35 kV, to transport smaller amounts of electricity relatively short distances. Power transformers reduce the high-voltage electricity from the transmission system to the lower distribution system level. The power transformers are housed together with control and protection devices in *distribution substations*.

The distribution system is divided into *primary* and *secondary* systems. The primary distribution system operates at between 2.4 and 35 kV. Some moderately large customers, typically industrial or large commercial, take their electric service from the primary system directly. Most customers receive their electricity from the secondary distribution system at voltages between 110 and 600 volts. The primary distribution system delivers power to distribution transformers which reduce voltage to the secondary system voltage levels. Secondary distribution systems typically serve groups of customers in neighborhoods. Unlike transmission lines, secondary distribution systems typically carry single phase rather than three phase power. Primary distribution may be either single or three phase.

Protective apparatus in the distribution system include circuit breakers in distribution substations that open automatically when a protective relay detects a fault (or short circuit) and fuses on the secondary systems that open when overloads occur. Many of the circuit breakers and switches in distribution circuits are manually operated devices, so restoring service after outages occur is usually done manually.

Nearly all electric utilities in the United States are connected to neighboring utilities through one or more transmission links, or *tie lines*. Each utility is responsible for providing the power used by its customers without taking power from neighbors unless alternate arrangements have specifically been made. Coordinated operation of interconnected systems is implemented through the institution of *control areas*. A control area is a geographic region with an *energy control center* (ECC) responsible for operating the power system within that area. The control area is defined electrically by telemetering equipment on all transmission paths into and out of the area. One or more utilities may make up a control area. The control area in figure 4-1 is interconnected to two neighboring control areas through transmission lines.

Energy control centers employ a variety of equipment and procedures: monitoring and communication equipment called *telemetry* to constantly inform the center of generator output and system conditions; *computer-based analytical and data processing tools* which together with engineering expertise specify how to operate generators and transmission lines; and governors, switches, and other devices which actually control generators and transmission lines. The control center equipment and procedures are typically organized into three somewhat overlapping systems which are sometimes integrated in a full *energy management system* (EMS). They are the *automatic generation control* (AGC) system which coordinates the power output of generators; the *supervisory control and data acquisition* (SCADA) system which coordinates transmission line equipment and generator voltages; and advanced applications, such as analytical systems to monitor and evaluate system security and performance, and plan operations.

COORDINATED OPERATIONS AND PLANNING

The electric power system is a complex entity comprised of many interacting electrical and mechanical parts. Utilities may have a dozen or more generating units and transmission lines, and hundreds of distribution systems serving hundreds of thousands of customers each with a variety of energy using devices. Coordinating the operation and planning of a utility's equipment to meet the demand for electricity is the responsibility of operating and planning systems. The integrated operation and planning of modern power systems represents decades of evolution and development.

Performance Standards

One underlying goal in planning and operating a power system is to provide electricity that meets customer requirements safely and reliably. This entails:

- providing electricity with the correct voltage and frequency to operate consuming equipment; and
- providing that power with an acceptable level of outages or service interruptions.

In practice voltage, frequency, and reliability may be viewed as constraints or standards which must be met.

Frequency Standards

A relatively constant frequency of 60 Hz is taken for granted in the design of customers' equipment such as motors, clocks, and electronics. Actual frequencies in U.S. power systems rarely deviate beyond 59.9 and 60.1 Hz, well within the tolerance of consumers' electronic equipment and motors.[2]

Some clocks work by actually counting the number of cycles (i.e., every 60 cycles is 1 second). Keeping correct time requires that total deviation from 60 Hz over time is small and balanced. For example, when frequency fluctuates, clocks slow down or speed up accordingly. Later, the frequency must be adjusted to correct the time. The total deviation, called *time error*, is very small and insignificant.

Power system equipment itself is more sensitive to frequency deviations than consumer equipment. In particular, the control systems of modern power systems are designed to be extremely sensitive to frequency deviations. To function, the control systems actually require very slight deviations and must closely monitor time error. (The slight frequency deviations are essentially used for communication between generators and the control system, as discussed later.) For this reason, standards for frequency are set by the utilities in designing their controls, and frequency fluctuations have virtually no consumer impact. Standards for frequency and time error are set by the Operating Committee of the North American Electric Reliability Council.

Besides maintaining a relatively constant system frequency around 60 Hz, another frequency requirement is to avoid *nonsystem frequencies*. Some electrical equipment creates nonsystem frequencies besides the normal 60 Hz power, which may propagate through a transmission or distribution system and damage other equipment.[3]

For example, harmonic frequencies, i.e., integral multiples of 60 Hz such as 120 or 180 Hz, superimposed on the desired frequency may cause communication equipment malfunctions. Standards for nonsystem frequencies have not been uniformly established, partly because severe problems have been limited.

Voltage Standards

Unlike frequency, which is the same at all locations in a power system, voltage varies from point to point. The voltages throughout a power system depend on the voltage output of individual generators and voltage control devices and the flows of power through the transmission system.

Some voltage standards for power delivered to customers are widely accepted and published by the American National Standards Institute (ANSI) (see table 4-1).[4] These standards are given both for normal, sustained conditions and for emergency conditions lasting a few hours. The less stringent shorter term standards allow system operators greater freedom in responding to emergencies. The selection of voltage standards for delivered electricity reflects an implicit balance between the cost of maintaining the standard and consumers' benefits.

The ANSI voltage standards have been developed because many types of customer equipment require certain minimum standards to function properly. For example, with excessively low voltage, electric motors function poorly and may overheat and lights dim. Overly high voltages, on the other hand, shorten the lives of lamps substantially and increase motor power which may damage attached equipment.[5]

Not all equipment has narrow voltage tolerances, however. Electric resistance space and water heaters work well over a wider range of voltages and are insensitive to fluctuations, for example.

The ANSI voltage standards do not apply for short-term voltage fluctuations lasting a few seconds or less. Switching transmission lines and generators on or off and turning on major appliances may create voltage spikes or drops. Voltage fluctuations may damage computers and other electronic equipment or cause lights to flicker. However, standards for short-term fluctuations are far less uniformly established than those for longer term voltage variations.

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[2] *Standard Handbook of Electrical Engineering*, Donald Fink (ed.) (New York, NY: McGraw Hill, 1978), pp. 20-46.

[3] *Handbook of Modern Electronics and Electrical Engineering*, Charles Belove (ed.) (New York, NY: John Wiley & Sons, 1986), pp. 2318-2319. E.F. Fuchs, D.J. Roesler, and F.S. Alashhab, *Sensitivity of Electrical Appliances to Harmonics and Fractional Harmonics of the Power System's Voltage*, Parts 1 and 2, IEEE Transactions of Power Deliver, vol. PWRD-2, No. 2, April 1987.

[4] American National Standards Institute, *National Electrical Safety Code—1987 Edition*, ANSI C2 -1987.

[5] D. Fink, op. cit., footnote 2.

Table 4-1—ANSI Standard Voltage Limits

	Voltage limits (in percent of nominal)			
	Normal operating conditions		Emergency conditions	
Nominal voltage	Minimum	Maximum	Minimum	Maximum
120-600	95	105	91.7	105.8
600-34,500	97.5	105	95	105.8

SOURCE: Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access, and Non-Utility Generation," contractor report prepared for the Office of Technology Assessment, March 1988, pp. 1-14.

Some industrial customers have installed their own protective gear to guard equipment against out of range voltages. With the proliferation of computers and other sensitive electronics, an increasing number of customers are purchasing protective devices which filter out voltage fluctuations.

Reliability Standards

Reliability is a measure of the ongoing ability of a power system to avoid outages and continue to supply electricity with the appropriate frequency and voltage to customers. In contrast to the standards for voltage and frequency, reliability goals reflect customer preferences for the trade-off between electricity prices and outages rather than the actual design and operating requirements of customer equipment.

Establishing objective, quantitatively derived standards that accurately reflect the value of service reliability has proven difficult. Ideally, standards should balance the customers' value placed on reliability with the costs of providing it. However, determining the value of reliability to customers has proven challenging because of the wide variance in customers' costs from an outage. Customer outage costs depend on a host of diverse factors including:

- the magnitude of the outage (the total amount of energy or power not supplied);
- how often outages occur, and the duration of the outage;
- how prepared the customer is;
- the type of customer (e.g., industrial or residential); and
- the time of day, day of week, and season of the outage.

Determining the cost to a utility of providing increased reliability is similarly challenging. Bulk system outages occur when generation and transmission are insufficient to meet total customer demand at any instant. However, neither loads nor the availability of generation and transmission can be forecast with great accuracy. In particular, relatively infrequent and unpredictable events (e.g., a lightning strike on a transmission line or sudden equipment failure) may suddenly reduce the availability of a critical generator or transmission line. Also, analyzing the joint reliability impacts of transmission and generation is challenging. Thorough examination of the complex interactions between individual power system components under the nearly endless array of possible conditions is analytically intractable. As a result, it is difficult to calculate the improved reliability resulting from adding new generation or transmission equipment.[6]

Further, even with high *bulk system* reliability, a large number of outages may occur. In fact, bulk system failures account for a relatively small portion of customer service outages, around 20 percent by one estimate.[7] The remainder is caused by distribution system problems, often the result of storm damage to distribution lines.

In lieu of more quantitatively derived and defined standards for reliability, engineering planners assume a variety of rules of thumb or de facto standards. Three of the most common reliability-related goals are:

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[6] For a comprehensive discussion of the challenges of evaluating reliability impacts focusing on the challenges of integrating generation and transmission effects, see Public Service Electric & Gas Co., *Composite System Reliability Evaluation: Phase 1, Scoping Study*, Electric Power Research Institute, EPRI EL-5290, December 1987.

[7] U.S. Department of Energy, "The National Electric Reliability Study: Executive Summary," DOE/EP-0003, April 1981, as cited in: *Power System Reliability Evaluation*, Institute of Electrical and Electronics Engineers, 1982, p. 42.

- loss of load probability (LOLP) of 1 day in 10 years,
- first (or second) contingency security, and
- reserve margins of 15 to 20 percent. (See box 4-A.)

These reliability standards specify the amount of capacity to be installed (e.g., reserve margins and LOLP), and how that capacity must be operated (contingency security). Thus, they play a central role in determining the constraints and capabilities of modern power system operations and planning.

While these indices are all commonly used, there are no uniform definitions of how they are calculated, in part due to the variety of conditions important to different utilities. For example, in calculating LOLP or reserve margins, a utility relying heavily on power imports may include the impact of transmission while other utilities do not. The choice of standard to attain is a matter of experience and engineering judgment as well as system specific characteristics and is not uniform across the country.[8]

Many parts of the country currently have higher bulk system reliability than that prescribed by the standards. The exceeded standards result from the current surplus capacity planned and built to meet high-load forecasts of the past two decades that did not materialize.

Whether current standards could be strengthened or weakened to the benefit of customers is speculative. Certainly, some customers may benefit from reduced reliability if accompanied by reduced electric prices, just as others may prefer higher reliability even with higher prices.

Operating and Planning Requirements

Given the performance standards for delivering electricity, there are three general functions for coordinated operating and planning. They reflect the dynamic and complex nature of power systems and their customers. The functions are:

1. following changing loads;
2. maintaining supply reliability; and
3. coordinating transactions of power.

In practice, operating and planning systems seek to perform these functions at minimum cost. This requires a tremendous amount of information, computing power, and communication capability, as well as extensive coordination within and among the various organizations involved.

Following Load

At each moment the supply of power must equal the demand of consumers. However, demand changes continuously and occasionally unpredictably. Some load patterns tend to repeat approximately with the time of day, day of week, and with the season. Figure 4-3 shows a weekly pattern of demand for a U.S. utility. The vagaries of weather, economic conditions, consumer behavior, and in the longer term, technological change all impede the ability to forecast accurately. The continual and sometimes unpredictable changes in demand require coordination systems to be able to follow loads from moment to moment (called *regulation*) and from hour to hour (called *ramping*) as well as plan supplies flexibly for the longer term.

A fundamental constraint in following loads involves ensuring that generating units and transmission equipment operate within design tolerances. For example, power system equipment used for generation, transmission, and distribution has certain voltage requirements, much like consumer equipment. Standards for power system voltages are set by system engineers based on site-specific equipment design and operating requirements. Some power system equipment requires voltages within fairly narrow tolerances to operate properly. Other power system equipment, particularly some transformers, are designed to function over a wide range of voltages. Similar constraints apply to the ability of transmission equipment to accommodate power flows. The capabilities and constraints of power system equipment are discussed in greater detail later in this chapter.

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[8] See ch. 6 for a discussion of standards in different regions.

Box 4-A—Three Common Reliability Standards

Loss of Load Probability (LOLP)

LOLP is a measure of the long-term expectation that a utility will be unable to meet customer demand. Many utilities prescribe a standard LOLP of 1 day in 10 years. This means that given the uncertain failure of generation and transmission equipment and variations in customer demands, engineering analyses predict that there will be a bulk system outage for 1 day in a 10-year period.[1] The LOLP specifies neither the duration of the outage (e.g., whether the outage lasts several seconds or an hour) nor the magnitude (whether the outage affects one distribution substation or the entire system). Different utilities use different definitions of LOLP; there is no single consistent method of calculating it.

Contingency Security Criteria

After a major system component such as a generator or transmission line has failed, the redistribution of power flow on the remaining system will not automatically meet customer load. Even if sufficient generation is available, voltages and thermal loadings on the transmission system may fall outside acceptable limits, or the system may be unstable resulting in cascading failures. Utilities typically specify a reliability criterion of first (or second) contingency security, meaning that sufficient reserves of transmission and generation are immediately available such that the power system will continue to operate even if the one (or two) most critical components fail.[2] This is called the principle of **n-1** (or n-2) operation, and applies at all times, even when some elements are already out of service. For example, if three lines are out of service, the system's operation must be adjusted so that it will be able to stand the loss of a fourth line. Usually the critical components are the largest generators or transmission lines, or some component at a critical location in the network. In general, contingency studies assume that no more than one or two major failures will occur at a time (multiple failures are improbable unless there is some common cause). Contingency studies rely upon engineering judgment to decide which types of failures are reasonable or credible, since the large number of components makes enumerating all possible failure modes impractical.

Capacity or Reserve Margin

The reserve margin is the oldest and most traditional measure of reliability. *Reserve margin* is the difference between generating capacity and peak load expressed as a percentage of peak load. Similarly, ***capacity margin*** is the difference between capacity and peak load expressed as a percentage of *capacity* (rather than peak load).[3] Thus, for example, a system with a peak load of 4,000 MW, and installed capacity of 5000 MW has margins of: Reserve Margin = (5,000-4,000) ÷ 4,000 = 0.25, or 25%; and Capacity Margin = (5,000-4,000) ÷ 5,000 = 0.20, or 20%. The numerator for both measures is the same, but the denominator for is capacity margin is smaller, so the capacity margin is always smaller than reserve margins by a few percentage points. Capacity margin is the measure used by the North American Electric Reliability Council, although in practice most utilities refer to their reserve margins. Typically reserve margins of about 15 to 20 percent have been considered sufficient to allow for maintenance and unscheduled outages (corresponding to capacity margins of approximately 13 to 17 percent).[4] However, the amount of reserve margin required depends on system specific factors such as the number and size of generating units and their performance characteristics. For example, a system with a few large units will require higher reserves than a system with many small units.[5]

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[1] Recall that the bulk power system includes generation and transmission but excludes distribution. Thus, outages are expected to be more common than the LOLP standard indicates.

[2] North American Electric Reliability Council (NERC), *Transfer Capability—A Reference Document* (Princeton, NJ: 1980), pp. 6-7.

[3] Reserve margins and capacity margins are intrinsically related by the equation: Capacity Margin = Reserve Margin ÷ (1 + Reserve Margin).

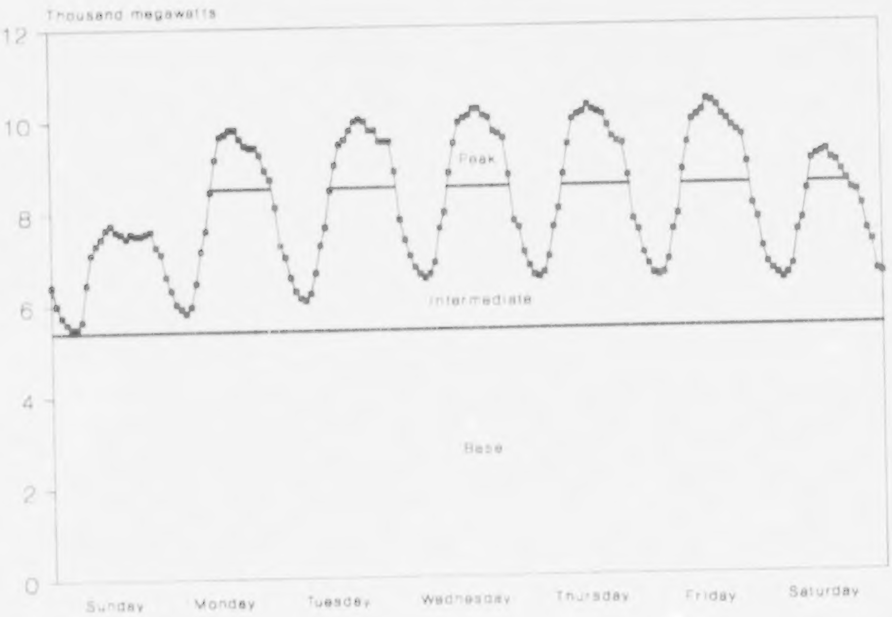
[4] A. Kaufman and K. Nelson, Library of Congress, Congressional Research Service, "Do We Really Need All Those Electric Plants?" August 1982.

[5] North American Electric Reliability Council (NERC), *Reliability Concepts* (Princeton, NJ: February 1985), p. 16.

Maintaining Supply Reliability

The cost and performance of generation and transmission equipment is variable and uncertain, as are customer loads. From one moment to the next, any piece of equipment may fail, either on its own or due to external influences (e.g., lightning strikes). Preparing for continued operation after equipment failure is called maintaining *security*. As defined by the North American Electric Reliability Council

Figure 4-3—Weekly Load Curve



SOURCE: Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access and Non Utility Generation," contractor report prepared for the Office of Technology Assessment, March 1988, pp. 2-3.

(NERC), "security is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components."[9]

Ensuring sufficient availability of supplies is called maintaining *adequacy*. Again according to NERC, "adequacy is the ability of the bulk power electric system to supply the aggregate electric power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components."[10] In addition to unexpected failure, virtually all equipment requires some maintenance, and has operating limitations that reduce availability. In the longer term, the cost and availability of fuels is uncertain, resulting in uncertain operating costs for generating units. In the longer term still, construction cost and schedules for new equipment are often uncertain, as is the demand for power. Maintaining adequacy involves addressing these constraints and uncertainties.

Coordinating Transactions

Nearly all utility systems are interconnected with other systems, allowing for a variety of transactions. Transactions may take a variety of forms, including: short-and long-term purchases and sales with neighboring systems; purchases from suppliers within a utility's service area (e.g., an independent power producer); operation of jointly owned power plants; and wheeling of power.[11]

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[9] North American Electric Reliability Council (NERC), *Reliability Concepts* (Princeton, NJ: NERC, February 1985), p. 8.

[10] Ibid.

[11] For a comprehensive discussion of the types of interutility transactions used, see: Energy Information Administration, *Interutility Bulk Power Transactions*, DOE/EIA-0418, October 1983.

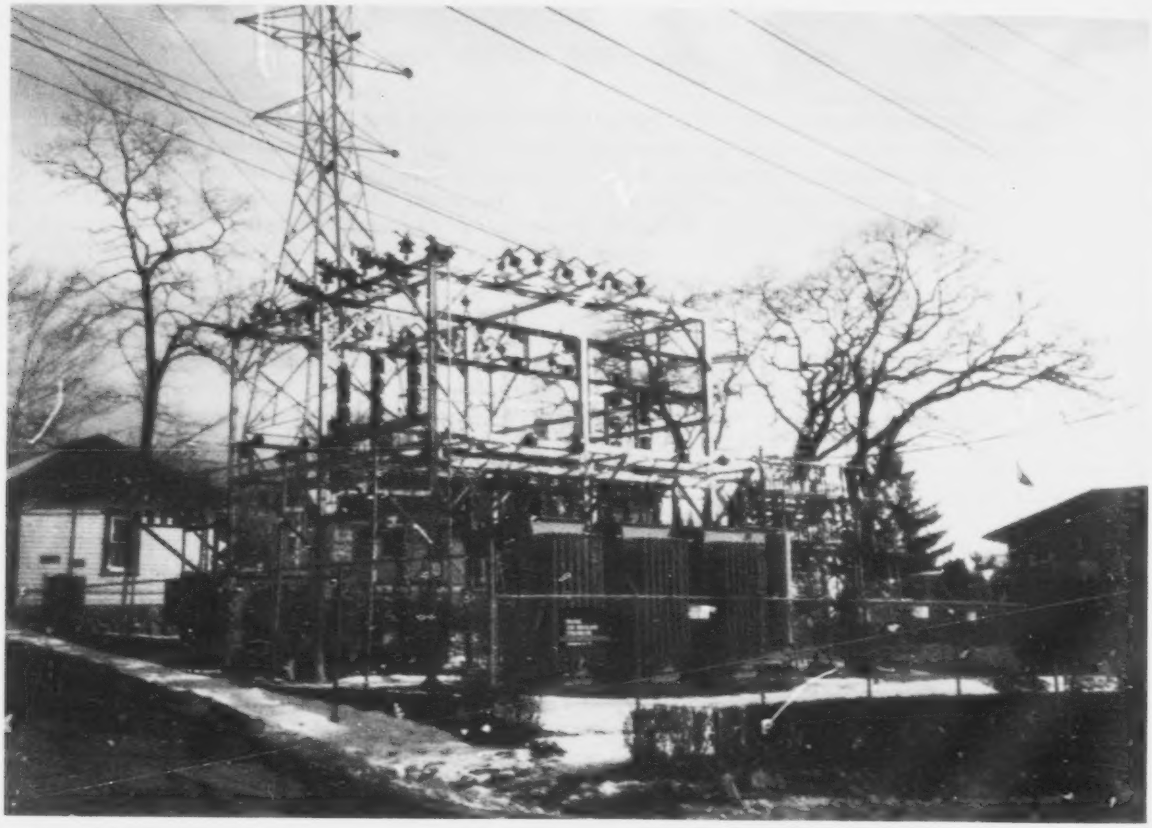

Photo credit: Casazza, Schultz & Associates, Inc.

An electrical substation

Except where contrary arrangements are specifically made, it is the responsibility of each utility to provide the power used by its customers without absorbing power from its neighbors or sending unwanted power to them. Through NERC, North American utilities have set standards for controlling inadvertent interchange.[12]

One requirement for inadvertent transactions is based on "area control error" (ACE), a measure of difference between the actual and scheduled interchange at any moment which also accounts for power frequency deviations. NERC guidelines specify both that ACE must be zero at least once in each 10-minute period and must not average beyond a specified level for any period. Controlling ACE and inadvertent power transfers requires careful scheduling and control of transactions between the entities as well as monitoring and recording the transactions for billing or other compensation.

Implementing Coordinated Operations and Planning

Performing the functions of following load, maintaining reliability, and coordinating transactions involves executing several coordinated operating and planning procedures.[13]

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[12] North American Electric Reliability Council (NERC), *Operating Manual* (Princeton, NJ: Dec. 1, 1987).

[13] For a more technical description, see example: Institute of Electrical and Electronics Engineers (IEEE) Committee Report, "Description and Bibliography of Major Economy-Security Functions, Parts I, II, and III," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-100, No. 1, January 1981, pp. 211-235.

The procedures each focus on different time horizons and different aspects of the power system (see table 4-2). Some procedures such as coordinating the energy output of generating units to balance demand are performed continuously. Others, such as planning generation additions, are performed far less often. The time horizon each procedure is concerned with also varies widely. For example, controlling energy input to a generator focuses on a time horizon of under a minute, while long-term planning may have a 20-year or more horizon reflecting the long construction time and useful life of generation and transmission equipment. Each time horizon beyond a few seconds requires forecasts of customer demand and performance of system equipment.

Governor Control of Generators for Load Following

At every moment, the power generated must balance the amount demanded to maintain the 60 Hz frequency required by both customers and the power system. Frequency fluctuations result from an imbalance between the supply and demand for power in a system. In any instant, if the total demand for power exceeds total supply (e.g., when a generator fails, or as demand increases through the course of a day), the rotation of all generators slows down, causing the power frequency to decrease. A similar process occurs in reverse when generation exceeds loads, with the governors reducing the energy input to generators to maintain frequency.

Controlling frequency involves balancing the supply and demand for power. Speed governors on most generating units constantly monitor frequency and regulate those units' power output to help balance demand and restore the frequency. The constant change in a unit's power output slightly increases maintenance requirements, and slightly decreases operating efficiency.

Power output from a generator does not change instantaneously. The rate at which a generator's power output can increase or decrease, called the *ramp rate* or *response rate*, depends on the type of generator. That is, the usefulness of a particular generator in regulating frequency varies from unit to unit. Large steam generating units such as nuclear power plants and large coal units generally change output levels slowly, while gas turbines and hydro units are very responsive. Table 4-3 shows typical response rates for different types of generators. The response rate is expressed in percent of rated

Table 4-2—Operation and Planning Functions

Function	Purpose	Procedures involved
Following load		
Frequency regulation	Following moment-to-moment load fluctuations	Governor control Automatic generation control (AGC) and economic dispatch
Cycling	Following daily, weekly, and seasonal cycles (within equipment voltage, power limits)	AGC/economic dispatch Unit commitment Voltage control
Maintaining reliability		
Maintaining security	Preparing for unplanned equipment failure	Unit commitment (for spinning and ready reserves Security dispatch Voltage control
Maintaining adequacy	Acquiring adequate supply resources	Unit commitment Maintenance scheduling Planning capacity expansion
Coordinating transactions	Purchasing, selling, and wheeling power in interconnected systems	AGC/economic dispatch Unit commitment

SOURCE: Adapted from F. Mobosheri, Southern California Edison, letter to Office of Technology Assessment, May 13, 1988.

Table 4-3—Typical Generator Response Rates[a]

Unit type and size	Response rate
Steam units (all fuels)	
10-50 MW	4.8% per minute
60-199 MW	3.8% per minute
200 and over	2.8% per minute
Hydroelectric	
10-59 MW	1-6% per second
above 60 MW	4-6% per second
Combustion Turbine	
All Sizes	55% per minute

[a] See "Power Plant Response," Institute of Electrical and Electronics Engineers Working Group on Power Plant Response to Load Changes, IEEE Paper TP 65-71, 1965, and *Survey of Cyclical Load Capabilities of Fossil Fired Generating Units* (Palo Alto, CA: Electric Power Research Institute, 1979) EPRI-975.

SOURCE: Power Technologies, Inc., "Technological Considerations in Proposed Scenarios for Increasing Competition in the Electric Utility Industry," contractor report prepared for the Office of Technology Assessment, March 1988, pp. 2-16.

capacity per minute or per second at which output can change.

The ramp rate of a generator reflects the *maximum* rate at which the unit's power output can change. Given this upper limit, each generator's governor is set to specify how rapidly and to what extent the unit actually will respond to frequency changes. Some, but not all units need to be on governor control to respond quickly. In fact, some units do not respond at all, but instead are set to produce a fixed power output. The amount of generation under governor control required to follow load depends on expected changes in load and on the ramp rates of the available controlled generators. System engineering analyses determine the amount of generation required to be under governor control. Setting the generator governors is a function with a slightly longer time horizon, discussed next.

Economic Dispatch and Automatic Generation Control for Load Following, Reliability, and Coordinating Transfers

Coordinated operation based on the incremental costs of generation, called economic dispatch, is one key to minimizing cost.[14]

The incremental production cost of a generating unit is the additional cost per kilowatthour (kWh) of generating an additional quantity of energy or the cost reduction per kWh due to generating a lesser quantity of energy. Incremental production costs depend on the cost of fuel and the efficiency with which the unit converts the fuel to electricity, and any other operation costs that vary with the level of power output. In economic dispatch, units with the lowest incremental costs are used as much as possible to meet customer demand. Typically, economic dispatch is entirely recomputed every 5 to 10 minutes.

Automatic computer control of generator output is used to implement the dispatch of generators in a control area. Automatic generation control (AGC) systems calculate what increase or decrease in each generating unit's output is required to maintain the balance between supply and demand in the least costly way. Based on AGC calculations, generator governors are reset to affect the change. An AGC system constantly monitors the power system frequency to determine whether increased or decreased output is required. The AGC system typically resets generator governors every 5 to 10 seconds based on an approximation of economic dispatch.

When governors balance supply with loads, high incremental-cost units such as combustion turbines may be used because they are able to change power output rapidly. The AGC systems set the governors on power plants so that power output from low-operating cost generators increases to displace output from more expensive generators that were used to control frequency.

To perform its job, an economic dispatch and AGC system needs cost and performance information about each of the power system's operable generating units. For example, the system must know the range of power each generator can produce (called the *control range*) and the ramp rate. Typically, the efficiency with which fuel is converted to electricity, and hence the incremental cost, depends on whether the plant is being operated at full or part capacity. Control ranges, efficiency, and incremental costs vary widely with the type of generator, and sometimes on contractual requirements for purchasing power.

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[14] See B.F. Wollenberg and A.J. Wood, *Power Generation, Operation and Control* (New York, NY: John Wiley & Sons, Inc., 1983); or A.S. Debs, *Modern Power System Control and Operation* (Boston, MA: Kluwer Academic Publishers, 1988).

Minimizing total cost often involves one utility purchasing electricity produced by another. Interutility transactions are sometimes very highly automated, as in the case of the Pennsylvania-New Jersey-Maryland interconnected system, which is one large control area with 11 member utilities acting as a tight power pool. In other cases, the process is less automated, carried out through brokerage systems or by system operators using telephones or small computer networks to exchange sale and purchase information.

AGC systems control both the planned and inadvertent power exchange between control areas. Interutility transactions are implemented by increasing the generation of the selling utility and decreasing that of the buying utility. When inadvertent, excessive, or insufficient exchanges occur, AGC systems adjust the governors on generating units to increase or decrease power output, correcting the amount of power transferred. To properly control interutility exchanges, AGC systems must have information on the planned schedule of power transfers and must constantly meter the actual power flows for comparison.

In calculating which generating units to operate and at what level, the dispatch system must also consider the effects of the transmission system. Dispatch systems commonly incorporate two principal effects. First, losses on the transmission lines may be significant in systems with widespread generation and loads. When this is the case, the dispatch systems must consider the incremental cost of transmission losses in addition to the incremental operating cost of generation. Accurately calculating incremental transmission losses is difficult and time consuming, however. Losses increase disproportionately with increases in power transfers and depend on the often indirect path of power flows. Both features result in computational difficulty for determining actual losses. However, some consideration of transmission losses is required. Typically, an approximate mathematical model of the losses is used.

The second transmission consideration relates to adequacy and reliability. The capacity to transfer power while remaining within voltage and load flow limits is a constraint on economic dispatch. When sufficient transmission is not available to deliver power from the lowest cost generators to loads, other generators must be operated. This is called operating off-economy. The dispatch system then needs to know not only the capacity of the transmission system and the current use but also the amount of capacity required for the transfer and the effect on system voltages. Again, due to the computational difficulties of calculating power flows, the dispatch system relies on another portion of the energy management system to determine the security (e.g., ability to withstand equipment failure) of the dispatch scheme chosen and override the economic dispatch if needed. That is the function of security constrained dispatch, discussed later.

Voltage Control for Load Following

The job performed by governors and AGC focuses on meeting frequency requirements economically as loads change. However, changing generation dispatch may also change voltages across the system. Voltages must be kept within design tolerances for a power system to provide acceptable service to customers. Maintaining voltage involves balancing the supply and demand of power, although in this case, it involves balancing *reactive* power (called VARs) rather than real power (see box 4-B). An imbalance in the supply and demand of VARs causes voltage to rise or drop across the power system. Understanding the pattern of voltages and reactive power flows is a complicated problem arising from the physics of electric systems.

Power system equipment creates the primary demand for VARs. Long, heavily loaded transmission lines typically consume VARs, as do power transformers and motors. One effect of reactive power flows is that the use of distant low-cost generating units may not be possible if sufficient VAR supplies are not available despite otherwise adequate transmission line capability.

Maintaining voltages to within the standards required by system equipment is the function of VAR control. Voltages at various locations are telemetered to the energy control center from various points in a power system and checked to ensure they fall within the acceptable range. When voltages begin to deviate from the acceptable range, both automatic and remotely controlled actions are taken using a variety of reactive power control devices. Supervisory control and data acquisition

Box 4-B—Real and Reactive Power

Power is the product of voltage (electrical potential or pressure) times current (the number and velocity of electrons flowing). In an AC system, both voltage and current vary sinusoidally over time with a frequency of 60 cycles per second (60 Hertz). However, the current and voltage are not necessarily in phase with each other. That is, the current may reach its maximum slightly before or after the voltage does in each cycle. *Active, or real power* results from current and voltage in phase with each other. Measured in watts, it is the power delivered to a load to be transformed into heat, light, or physical motion. *Reactive power* results from that portion of current and voltage which are not in phase. Measured in VARs (for Volt-Amps Reactive), it can be thought of as the flow of power stored (but not consumed) by electric and magnetic fields around circuit components.

That current and voltage may be out of phase results from a phenomenon called *reactance*.[1] When a voltage causes a current to begin flowing through a wire, a magnetic field forms around the wire opposing and delaying the change in current. When the voltage is reduced, the collapsing magnetic field again opposes and delays the reduction in current. The magnetic field may also induce or retard a current in nearby wires (e.g., other conductors in a transmission line). The overall effect of the forming and collapsing magnetic fields in delaying changes in current relative to voltage creates *inductive reactance, or inductance*. The larger the current, the larger the inductive effect.

Similarly, different voltages between circuit components (e.g., between conductors in a transmission line or between a conductor and the ground) create electric fields. These forming and collapsing electric fields result in *capacitive reactance* (or capacitance), in which current changes are advanced relative to voltage changes. The larger the voltage, the larger the electric field and the capacitive effect.

Capacitance and inductance exist in any piece of electrical equipment. When capacitance and inductance are balanced in a transmission line the voltage and current are in phase with each other. Then there is no net flow of reactive power. When the inductive effect is greater than capacitive effect the current lags the voltage at any point on the transmission line and the line is said to consume reactive power. Similarly, when the capacitive effect is greater, the voltage lags the current, and the line is said to produce reactive power.

A transmission line's operating voltage is determined by the line design, and the capacitive effect is constant. However, different real power flows on a line result from different currents, with fixed voltages. Thus, the inductive effect, due to magnetic fields caused by current flowing, increases as the amount of power flow increases. For this reason, low real power flows on a line may result in a high flow of produced reactive power. High active power flows on a line may result in a high flow of consumed reactive power.

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[1] Reactance is one part of the *impedance* to flow determining how much current will flow for a given voltage. The other part of impedance is called *resistance*, which occurs as the flowing electrons collide with atoms of metal in the conductors. Resistance is a form of electrical friction which creates heat.

SOURCE: Office of Technology Assessment, 1989.

systems combine telemetry of voltage to the control center and remote control of VAR supplies.

VARs may be supplied or consumed by generators either automatically or under the control of system operators. Whereas real power output of a generator is controlled by governors controlling the energy input, reactive power is regulated by adjusting magnetic fields within the generators. As with real power, reactive power output from a generator is limited. Limits to reactive power output are due to possible overheating within the generator resulting from high levels of output. Control of generator VAR output and off-economy dispatch are common modes of voltage control on the bulk power system.

Other automatic and manual voltage control devices include capacitors, shunt reactors, variable transformers, and static VAR supplies. These devices may be installed at various locations in the transmission, subtransmission, and distribution systems. Voltage problems resulting from VAR flows are one major cause of transmission limitations. Also, improved VAR control may help reduce operating costs by reducing VAR flows.[15]

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[15] Scientific Systems, Inc., *Optimization of Reactive VAR Sources in System Planning*, EPRI EL-3729, November 1984.

As a result, the use of these devices is likely to increase over time. VAR-related transmission limits, and some approaches to reducing them are discussed in the final section of this chapter.

Security Constrained Dispatch for Reliability

The combined control of real and VAR generation output and other VAR sources may not result in secure performance. Maintaining system reliability is the job of *security constrained dispatch* of generation.

The objective of security constrained dispatch is to prevent the possibility of "cascading outages" in which the failure of one or two generators or transmission lines results in the overloading and failure of other equipment. A key to security constrained dispatch is scheduling generation in a "defensive" mode so that the power system will have enough supplies ready to continue operating within emergency standards for frequency, voltage, and transmission line loadings should contingencies occur. In a sense, security constrained dispatch accounts for reliability constraints on transfer capacity.

An important parameter of the defensive operating practice is that transmission capability must be held in reserve for the possible occurrence of a major failure in the system. Generating units are similarly held in reserve. Idle generating units and transmission lines with below capacity power flows may mistakenly seem to be surplus, when in fact they are essential for reliability. This difference between appearance and reality must be carefully noted in changes to the power system.

The analytical methods used are based on load flow calculations of real and reactive power flows in the power system. Control center operators typically examine a series of contingency cases to determine the most severe contingency and the resulting power transfer limit. When that limit is lower than present transfers, the economic dispatch is recalculated to reduce the transfer to acceptable levels and implemented by the AGC and Supervisory Control and Data Acquisition (SCADA) systems. By dispatching generating units "off-economy," security constraints result in higher operating costs.

Power flow and contingency analyses needed for security constrained dispatch are time-consuming and computationally difficult. Complex systems with many generating sources, transmission components, and loads have complicated flow patterns, resulting in a large number of contingencies to be examined. Because of the computational difficulties, security constrained dispatch often relies on planning and analysis to determine transfer capabilities and constraints. The result is an approximation of actual security constraints. Utilities are increasingly developing automatic energy management systems by combining the data acquisition capabilities of SCADA systems with load flow and other analytical tools needed to evaluate security in real time.[16]

Unit Commitment for Load Following, Reliability, and Coordinating Transactions

Generating units typically need to warm up before operating (unlike transmission lines). To be ready for operation, generators must not only be warmed up, but must also be rotating in synchronism with the 60 Hz of the power system. This requires utilities to establish a *unit commitment plan*. Unit commitment plans seek to ensure a sufficient supply of generation for immediate operation in case of contingencies such as failure of a generating unit or transmission line. Also, the plan ensures that sufficient generation under governor control is available for regulating frequency in response to changing loads. Such generation which is synchronized and ready to serve additional demand is called *spinning reserves*.

Unit commitment plans also specify which units will be warmed up and cooled down to follow the cycle of loads over the course of a day, week, or season. Utilities calculate unit commitment schedules which minimize the total expected costs of operation and spinning reserves required to maintain reliability and meet expected changes in demand. Often, utilities also schedule power purchases from other utilities. New unit commitment plans are typically established each day or after major plant outages or unexpected load changes.

Unit commitment planning requires a vast amount of information. Virtually all the information about generation and transmission operating cost and availability required by the dispatch and security systems is also needed to develop the best unit commitment schedule. In addition, the time and cost to warm up generating units and the availability of personnel to operate generating units must be considered. These factors vary depending on the type of generating unit. Unit commitment schedules are typically developed using computers to perform the numerous calculations for identifying the minimum expected total costs.

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[16] "SCADA/EMS Market Still Vibrant," *Electrical World*, vol. 201, No. 10, November 1987, p. 36.

Scheduling Unit Maintenance for Reliability and Coordinating Transactions

Scheduling maintenance is similar to unit commitment, although with a somewhat longer time frame. The objective is to schedule needed generation and transmission equipment maintenance to meet reliability goals and minimize the expected cost of operation. Maintenance scheduling requires information about each piece of equipment's need for maintenance, and the expected customer demand. Maintenance schedules may be established annually or following unexpected equipment outages.

System Emergency Operations and Restoring Power for Reliability Emergencies

System emergencies occur when there simply is not enough capacity available either within the utility or through neighboring systems to meet load. When voltages and frequencies deviate too much as a result, relays and circuit breakers may isolate overloaded generators and transmission components from the system, exacerbating the imbalance between supply and demand. Emergency operations involve avoiding cascading outages by reducing the power delivered to consumers. In the extreme, this requires disconnecting customers from the system. Plans for load shedding must be coordinated with the automatic isolation of generating units that occurs under abnormal frequency and voltage conditions. Restoring power also requires coordination of the system components and the devices used to isolate the loads. Following system failures, restoration requires that some generating units be capable of starting on their own, called "black-start capability." Not all generators have this capability, typically taking their starting power from the system.

Planning Generation and Transmission Capacity

System planning has the long-term focus of adding adequate generation and transmission capacity to meet changing demands reliably and at low cost. Planning begins with forecasting both the changing patterns of demands on the system, as well as the costs of alternate fuels and resources. Based on these forecasts, planners implement generation expansion plans to meet those changing conditions. Plans for new transmission facilities must reflect both the changes in demands and in generation. Planning new generation and transmission facilities is typically a utility responsibility, often performed with considerable regulatory oversight. Also, because of the interconnected nature of utilities, plans are also usually coordinated with power pool and NERC region review to assure reliability.

Uncertainty in forecasting presents acute problems for planning, in which time horizons of 2 to 30 years reflect the construction and operating lives of new generation and transmission facilities. In recent decades, forecasts of long-term load growth have often been highly inaccurate. In addition to uncertainty over long-term trends, load forecasting is complicated by the effects of unpredictable (but inevitable) variations in weather and economic cycles from year to year. Similarly, the significant uncertainty and swings in fuel prices make operating costs highly uncertain. The result of this uncertainty is a mix of facilities which may not ideally meet existing conditions (e.g., with surplus or deficit generating capacity). At any time, the existing mix of generation and transmission capacity reflects previous expectations of fuel prices, construction schedules, and customer demand which may be quite different from actual outcomes.

Generation expansion planners have many supply technologies to choose from, with a wide range of cost and performance characteristics. Typically, generating units with relatively low operating costs (e.g., nuclear, coal, hydroelectric) have been relatively expensive to build and have had long construction periods. Generating units that are relatively quick and inexpensive to build (e.g., gas- or oil-fired combustion turbines) have had relatively high operating costs. Because of uncertain fuel price and availability, planners often seek a diverse mix of generating technologies.

The growing interest in conservation and load management technologies, together called demand side management (DSM), has added further options to expansion planners. DSM has an even wider variety of performance and cost characteristics. Increasingly, system planners must also consider nonutility generation in transmission and generation planning. Numerous computer-based analytic tools have been developed to aid planners in evaluating the financial and economic impacts of different capacity expansion plans under a variety of demand and economic scenarios.

Choice of generation types is often broken into base-load, intermediate, and peaking reflecting the time-varying patterns of demand (figure 4-3). Plants chosen for base-load operation typically have relatively high construction costs justified by low operating costs. Because of the limited hours they're expected to operate, generating units with low capital cost are chosen for peaking duty, even though they may have higher fuel and operating costs.

The varied operating and cost characteristics of different generation technologies give each advantages and disadvantages for use in a power system. System planning must ensure adequate controllable generation for regulating both frequency (by controlling the output of active power) and voltage (by controlling the output of reactive power). The costs and ability to operate as spinning reserves and to warm up or cool down under unit commitment plans are also critical. Table 4-4 summarizes some of the key characteristics considered in planning of both existing and prospective generation facilities.

Transmission system expansion must be adequate to accommodate generating unit additions as well as the changing patterns of loads. Siting of power plants is integrally related to transmission requirements, and costs and capabilities need to be considered together. Depending on the location of a new generating unit relative to the existing transmission system, new transmission may or may not be required. Transmission additions may also be needed to increase transfer capability to neighboring utilities. The appropriate level of interutility transfer capability depends on the opportunities such as exchanging reserve generating capacity and obtaining lower-cost energy and capacity.[17]

A variety of engineering-analytical tools are used to determine the type of transmission additions needed, and the overall impact on the existing system. These tools help planners examine such factors as:

- the effects on real and reactive power flows,
- the resulting transmission losses,
- the need for voltage and reactive power control devices on the system, and
- the transient stability and contingency security of and the impacts on system reliability.

Table 4-5 summarizes some of the key characteristics of both existing and prospective transmission facilities which are considered in planning.

INCREASING TRANSMISSION CAPABILITY

Transmission systems have a variety of uses such as:

- delivering power from a utility's supplies to its customers,
- providing for interutility exchanges of economy energy, firm capacity and shared reserve capacity,
- integrating nonutility generation, and
- wheeling power.

In integrated power systems, performing these functions involves moving power from a large number of generators to a large number of loads along a network of transmission lines. At times, transmission constraints occur which limit the ability to move power from one location to another. This section describes the constraints on a system's transmission capability and some of the technologies available to ease those constraints.

Limits to Transfer Capability

Basic physical principles largely determine the transmission capability of a power system. *A few fundamental factors underlie the physical limitations to transfer capacity of power systems.* The limitations may be due to either the abilities of individual components, or to the requirements and challenges of operating the overall system. Individual transmission line components have specific voltage requirements and limited current-carrying or thermal capability, either of which may constrain their use. System-related constraints involve the complex interactions between individual generators, transmission circuits and their control system, and the needs for maintaining adequate reliability. Table 4-6 summarizes the constraints on power transfers.

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[17] For a discussion of planning interutility transmission systems, see Public Service Electric & Gas Co., *An Approach for Determining Transfer Capability Objectives*, Electric Power Research Institute, EPRI EL-3425, March 1984.

Physical laws alone do not dictate the absolute amount of transfer possible. Rather, they indicate a trade-off between level of transfers and reliability. There is no simple power network equivalent of the telephone company's busy signal. For example, higher transfers decrease transmission reserves, increasing the possibility of an outage occurring. As a result, transfer capability depends on both physical characteristics and the reliability standards and procedures used. (Recall that reliability criteria are somewhat subjective and not set on a quantitatively derived balance between the utility's costs of providing reliability and the consumers' benefits of uninterrupted service.)

Determining transfer capability and opportunities for improvements can be a challenging matter of balancing economics, reliability, engineering, and policy. Developing meaningful estimates of transmission capability requires considerable engineering expertise, data, and analytic tools. This challenge arises because capability is not merely the rating of a single line or a few lines. Rather, transmission capability is a function of the strength of the system as a whole, including not only the transmission lines but the generating units as well. For example, spinning reserves of generation located near loads may reduce the amount of transmission capacity from distant generators which must be held in reserve to maintain reliability.

Transmission capability also varies over time, further complicating any assessment of the adequacy, limitations or opportunities for expanding capabilities. It varies as switching operations occur and as demand, generation, and transmission patterns change. Fluctuating patterns of demand, changing availability of generators and transmission lines, even weather, all affect capability.

In some cases, there may be a single binding constraint that would produce a large increase in capability if it could be relieved. More often there are multiple constraints on a single transmission line, or constraints on many lines at the same time so that reliving a single constraint would make practically no difference. For example, in the PJM system, west to east transfers are limited by voltage-related factors 85 percent of the time and thermal limits for the remainder.[18]

Although this section discusses physical constraints, there are also institutional constraints on power transmission. Even with sufficient physical capability, some economically advantageous transfers may not take place. For example, lack of regulatory approval, lack of intercompany agreements or contractual basis, or simply lack of knowledge of economic opportunities may all prove real and significant impediments to full use of transmission capacity.

Constraints on Individual Components

Power is transmitted when the line voltage causes current to flow in the conductors. The amount of power an individual line carries is proportional to the product of the current and the voltage. However, every transmission line is limited in the amount of power it can transmit by constraints on voltage and current. Flows of reactive power limit both the voltage and current capacity.

Thermal/Current Constraints

Current flowing causes conductors to heat up. The amount of heat individual components can tolerate limits the amount of power than can be transmitted. Heating causes the metal conductors to expand and sag. The resulting reduced clearance from the conductor to the ground, towers, and other conductors exacerbates flashover constraints. Excessive heating may also result in a permanent stretching and lead to brittleness and a shorter lifespan. Substation equipment is also subject to thermal limitations. Excessive heat can destroy the materials used in transformers and other terminal equipment.

A thermally overloaded component may reach its critical temperature within seconds, minutes, or hours, depending on its previous temperature, its

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[18] Casazza, Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access*, OTA contractor report, March 1988, p. V-4.

Table 4-4—Key Physical Characteristics of Generating Plants

- Operating cost
  - Fuel type and cost
  - Efficiency
- Control ranges
  - Real power
  - Reactive power
- Startup costs
- Ramp rates
- Fuel availability
- Expected equipment failure—availability
- Maintenance requirements and costs
- Environmental impacts and emission requirements
- Site availability
- Location relative to transmission and loads
- Construction cost and lead time
- Lifetime

SOURCE: Office of Technology Assessment, 1989

Table 4-5—Key Transmission Planning Characteristics

- Location and capacity of individual lines
- Equipment voltage requirements
- Capability of VAR support equipment
- Transmission losses
- Equipment failure rates
- Maintenance requirements
- Environmental impacts
- Rights-of-way and substation site availability
- Construction cost
- Construction lead time
- Lifetime

SOURCE: Office of Technology Assessment, 1989

Table 4-6—Transmission Capability Constraints

- **Physical constraints**
  - *Individual line constraints*
    - Thermal/current constraints
      - Conductor sagging, equipment lifetime
    - Voltage constraints
      - Flashover, corona, and terminal equipment requirements
    - Reactive power flow and voltage
  - *System operating constraints*
    - Distribution of power flows (parallel path and loop flows)
    - Contingency security
    - Stability (steady-state and transient)
- **Institutional constraints**
  - Interutility agreements
  - Regulatory approval

SOURCE: Office of Technology Assessment, 1988.

physical characteristics, amount of overload, and weather. Therefore it may be able to carry a heavy current for a short time, a lesser current for a longer time, and a still lesser one indefinitely. The latter current is the component's "normal" rating, applicable to normal operation. "Emergency" ratings are currents that can be carried for shorter times on the assumption that the loadings can be relieved by changes in generation dispatch or reductions in loads within the assigned time period.

Thermal ratings are usually established for loadings occurring for different periods of time—10 minutes, 30 minutes, 4 hours, etc. The ratings are typically based on current flows rather than the actual temperatures of transmission line equipment. The actual temperature depends not only on current, but on ambient weather conditions including temperature, wind speed, and icing. Identical components may have different ratings due to such factors as the expected ambient weather conditions and the reduction in equipment life considered acceptable by the utility.

Voltage Constraints

The design of a transmission line specifies the minimum and maximum operating voltages. Voltages exceeding the maximum may cause electricity to flashover (i.e., arc between a conductor and the ground or the tower), rather than travel along the line. High voltages may also cause corona discharge (i.e., ionized air molecules surrounding the line resulting from high electric fields), creating noise and radio interference. The maximum voltage allowable on a line depends on its height, spacing of the conductors and insulators, and weather (e.g., corona is exacerbated by high humidity, rain, or snow). Excessive voltages may also destroy transformers and other terminal and substation equipment by breaking down their insulation.

Reactive Power Flows and Voltage

As discussed earlier, reactive power flows may cause voltage to rise or drop significantly along transmission lines, particularly long ones. With low real power flows on a transmission line, capacitive reactance may create high voltages along the line, exacerbating high voltage constraints.

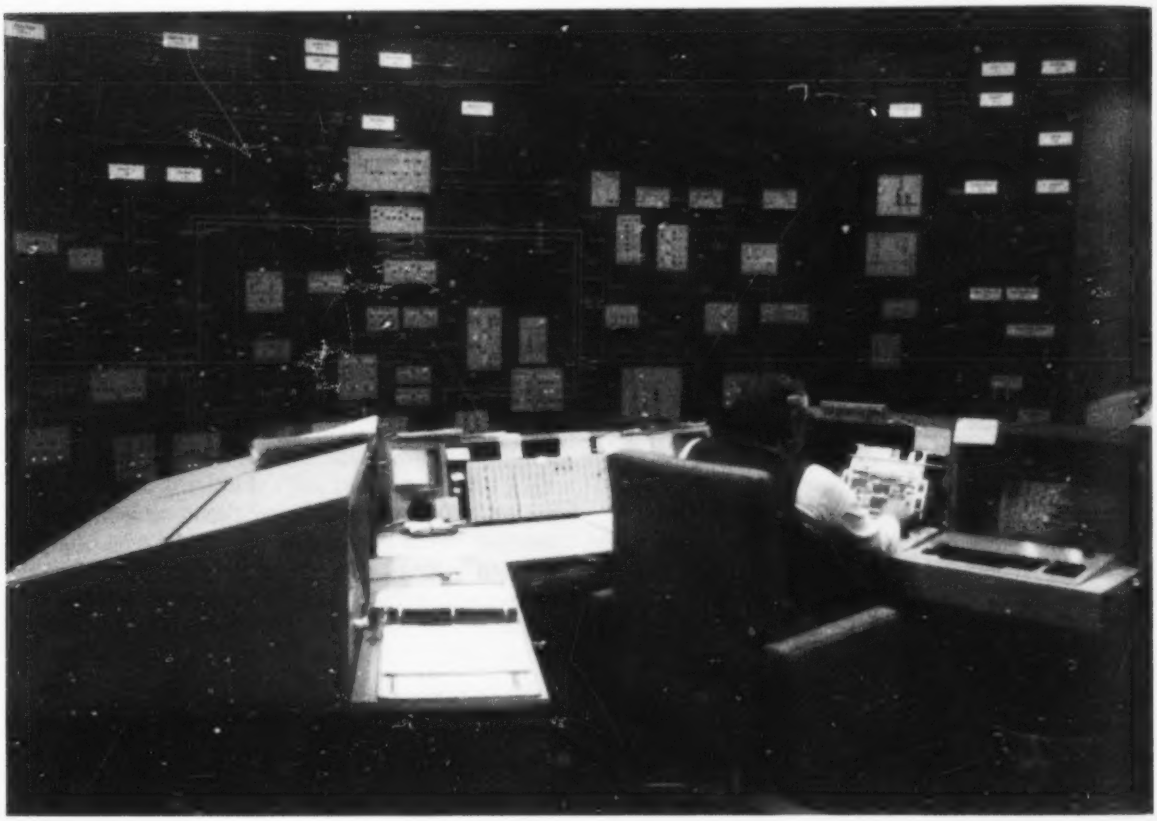

Photo credit: Casazza, Schultz & Associates, Inc.

An energy control center

Similarly, increasing the real power flow on a line also increases the line's demand for reactive power. As the flow of reactive power increases, the voltage along the line drops significantly. If as a result of reactive power flows, voltages fall below the design minimum, transformers will not function and either power cannot be transferred or the voltage of power delivered to customers will be outside the allowable range. Thus, the ability of generators and other VAR control devices to supply reactive power limits the amount of real power which can be transferred. Since the amount of reactive power required by a transmission line increases with line length, reactive power problems typically affect long lines.

System Operating Constraints

Parallel Path Flow: Distribution of Power

The flow of power in a transmission network is dictated by the laws of physics. One of the key laws is that power may flow on all available paths between the generator and the load. This is called *parallel path flow* (which is a slight misnomer, since the lines are not necessarily parallel).

Generally, the amount of power flowing on any path of a network is inversely proportional to that path's impedance. The impedance may be thought of as an "electrical length," which depends on both the actual length and the voltage of the path. (One mile of 500-kV line has approximately one-fifth the impedance of a mile of 230-kV line.) Also, a path's impedance to power flow does not necessarily reflect the transfer capacity of that path.

The distribution of power flows and the inability to control the flows has two important implications for determining transmission system capability. First, *the transmission capacity of a network is not the sum of the power that could be carried on each line alone. Rather, the capacity is constrained by the weakest link*. The amount of power that can be transferred from one area to another by a transmission system is the smallest power transfer at which one of the components reaches a thermal or voltage limit. (See box 4-C.)

Second, *the capability of transferring power from any generator to any load on the system depends on the other transfers occurring simultaneously*. The power flow from a generator to a load divides onto each pathway to some extent. Even indirect or distant lines may receive some of the flow and thus have part of their capacity used up. As a result, the capacity remaining for additional transfers between other generators and loads depends on the other transfers since they essentially share the same transmission paths.

Parallel path flows and resulting transmission problems can occur both within a single utility and between interconnected utilities exchanging power. Parallel path flows crossing the boundaries of utilities along paths not contracted for, or scheduled, are called *loop flows*. (See box 4-D.) In interconnected systems, such as those in the United States, loop flows are common.

System Stability

In an electrical generating network all generators rotate in unison, or synchronism, at the system frequency of 60 Hz. The ability to maintain synchronism is called stability. Transmission capability may be limited by instability. Normally, a disturbance increasing or decreasing the speed of one generator will cause small changes in the unit's power output, tending to bring that generator back to the common speed of the system. Instability is a condition in which this stabilizing process does not occur, and some generators speed up with respect to others, possibly causing the system to fall apart.

Two types of stability can be classified according to the magnitude of the disturbance: steady state and transient.[19] Steady state stability refers to the ability of the system to withstand small changes in loads. Transient stability refers to the ability to withstand large disturbances, such as the failure of a transmission line or generating unit. System engineers use complex computer programs representing the generators, controls, loads, and the network itself to examine which operating conditions (e.g., power flows on the transmission system) are stable and which are not.

Contingency Security

A major disturbance such as the failure of a generating unit or transmission component causes changes in real and reactive power flows and voltages around the system. As discussed earlier, the n-1 contingency security standard for reliability requires that a system continue functioning without cascading failures caused by thermal overloads, or excessive voltage drops or sags, or instability if any single component should fail without notice. Voltage control devices and generating units are set to respond to a contingency to restore the frequency, voltages, and power flows to acceptable levels. Because of the possibility of a major disturbance, the transmission system's capability of carrying power is limited not only by the actual flows but by the flows that would exist if a given contingency should occur. (See box 4-C.)

The standard approach to avoid such cascading failures is to operate in a *defensive or preventive mode*. In this mode, generation is dispatched and flows are maintained so that sufficient generation and transmission capacity is held in reserve to ensure that the resulting redistribution of power would remain within emergency ratings following the most severe single contingency.

While the defensive mode is essential for reliability, it may require operating more costly generating units when lower cost units are available. There is an alternative to defensive scheduling of generation and transmission, that of developing

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[19] Institute of Electrical and Electronics Engineers (IEEE) Committee Report, "Proposed Terms and Definitions for Power System Stability," *IEEE Transactions on Power Systems*, vol. PAS-101, No. 7, February 1986.

Box 4-C—Example of Transmission Constraints

The transmission capability between two points in a system may be limited by individual component constraints or by network constraints. Individual line constraints may be exacerbated by parallel path flows in the network. This highly simplified example shows some of the different constraints and their impact on overall transmission capability.

Component Constraints

Consider the very simple transmission network illustrated in figure 4-4. Three parallel transmission lines connecting a generator to a load. Each line has a capacity of 100 MW, above which it is constrained both thermally and by voltage. That is, increasing power flows above 100 MW by increasing current would cause overheating and sagging of the line. It would also increase reactive power demand, reducing the voltage at the receiving end below acceptable levels. Increasing power flows by increasing voltage would cause flashovers, corona discharge, or possibly destroy terminal equipment. If all three lines could be fully utilized, the system would have the ability to transfer 300 MW.

Parallel Path Flows

Because of different path lengths, the power transmitted may divide unequally on the three lines. Assume that the division is in the ratios of 10:9:8. Because of the uneven division, when Line A carries its rated power of 100 MW, Lines B and C carry only 90 and 80 MW respectively. Any attempt to transmit more power would increase the loading on all three lines and overload Line A. Thus, due to the impact of parallel path flows, the total capacity is only 270 MW.

Contingency Security Constraints

Using the defensive mode to meet the "n-1" contingency security requirement reduces the transmission limit even more. If Line B were to suddenly fail, perhaps after a lightning strike, Lines A and C would receive the additional flow and be loaded to 150 MW and 120 MW respectively. To prevent the possibility of an overload, the allowable power transfer is only 180 MW. Then the normal loadings are limited to only 67, 60, and 53 MW respectively, and the emergency loadings do not exceed the rating of 100 MW. The three 100-MW lines form a system capable of safely carrying only 180 MW, or 60 percent of their total individual ratings.

Transient stability studies of this system may indicate that the two generators will lose synchronous operation after a disturbance such as the line loss, even though no individual components are overloaded. That is, one generator may slow down while the other accelerates, as both respond to the new voltages and power flows. If this is the case, stability concerns may require further limiting transfers.

SOURCE: Office of Technology Assessment, adapted from Casazza-Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access*, OTA contractor report, March 1988.

special protection systems for responding rapidly enough to prevent cascading failures after a disturbance occurs. Such a mode of action is referred to as *corrective or remedial action*. Remedial action might involve measures including tripping (or rapidly disconnecting) a remote generator while rapidly increasing the output of a nearby generator when a specific contingency occurs. It is typically used when the preventive mode of operation would entail a heavy economic penalty.

According to the North American Electric Reliability Council (NERC), corrective action systems are being considered more frequently as an alternative to defensive generation scheduling.[20] NERC notes that widespread application of these more complex schemes may affect future power system reliability since system security becomes dependent upon the correct functioning of these special protective systems. To provide the same reliability as the defensive mode, special protection schemes must either be highly reliable or have built-in redundancy.

In practice, limits caused by contingency security are challenging to analyze. Circuit configurations are far more complex than the example of box 4-C,

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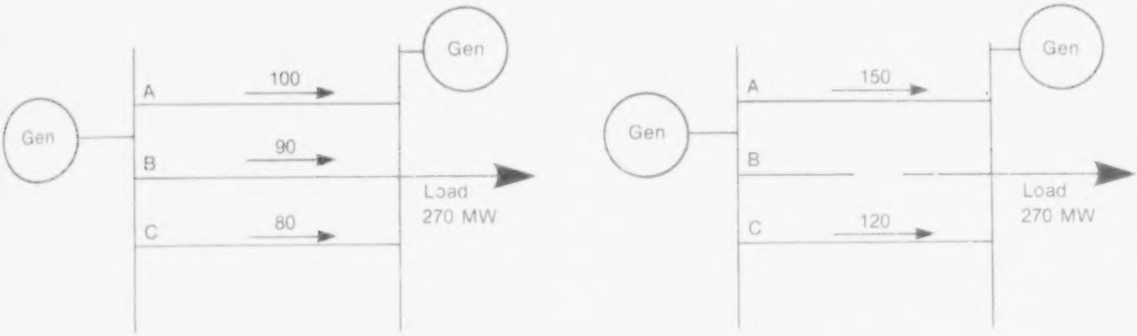
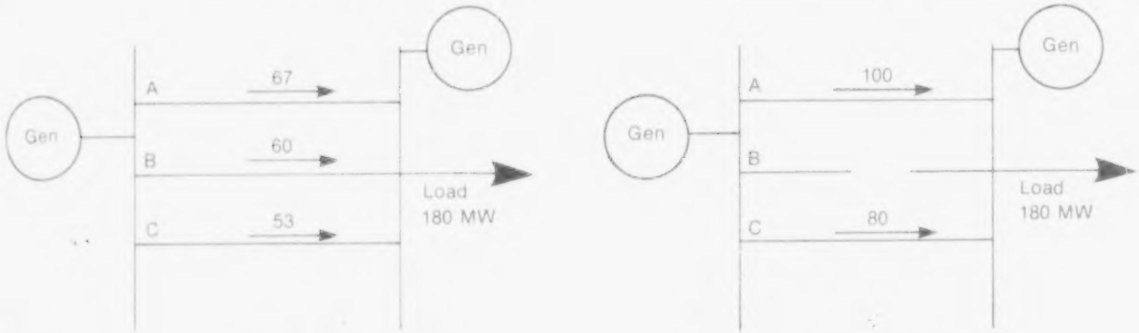
[20] North American Electric Reliability Council, *1987 Reliability Assessment—The Future of Bulk Electric System Reliability in North America, 1987-1996* (Princeton, NJ: October 1987).

Figure 4-4—Transmission System Limitations (all lines rate 100 MW)



(a)
All lines in service.
System loaded without considering contingencies.
Line A at rated loading.

(b)
Outage of Line B
System loaded without considering contingencies.
Lines A and C overloaded.



(c)
All lines in.
System loaded to "n-1 contingency limit"

(d)
Outage of Line B
System was loaded to "n-1 contingency limit" before
Line B tripped.
Line A at limit. No overloads.

SOURCE: Casazza, Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access*, OTA contractor report, March 1988.

and the redistribution of power flows after some equipment failure is complicated. Also, both real and reactive power flows and their impact on voltage and thermal limits must be considered. Moreover, following a disturbance, the transition to the new equilibrium state is not instantaneous. Rather, the change occurs over time as generating units and voltage control devices react and interact with each other. Thus, stability analyses must examine not only whether the new state following a disturbance is stable, but also whether transition to a new stable state will occur.

Prospects for Increasing Capability

Assuming that an increase in transmission capability is desired, what can be done? There are possibilities for mitigating all types of constraints. Options for upgrading both the transmission system and generators may be useful. Options include:

1. increasing the thermal or voltage capacity of an individual existing line,
2. improving the control of reactive power and voltages on a network,

Box 4-D—Loop Flows in the Western System Coordinating Council (WSCC)

Loop flows, the unscheduled use of another utility's transmission resulting from parallel path flows, is common in the WSCC as in other parts of the United States. The WSCC transmission system has the general shape of an elongated doughnut including a western section of lines joining Oregon and California; an eastern section running generally from Montana to Arizona; a section in the Northwest; and a section from southern California to Arizona. Figure 4-5 shows a simplified view of the WSCC doughnut.

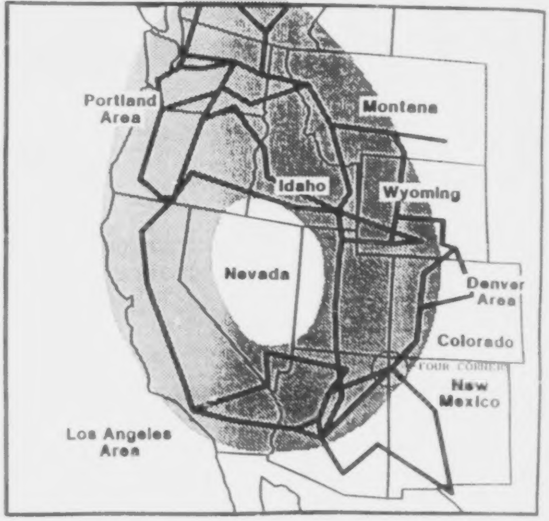
Because of the shape of the transmission system and the physical laws of electricity, whenever power is sent from one part of the doughnut to another, the flow is split two ways; some goes clockwise, and some counterclockwise. For example, if 1,000 MW of power is sent from the Montana-Wyoming area to the Pacific Northwest, only 580 MW of this power flows along the relatively direct counter-clockwise path, as seen in the figure below; the remaining 420 MW flows clockwise through California and north through the western lines. The flows due to simultaneous transactions carried on at the time are superimposed on each other depending on their amount and direction. For example, a sale from the Northwest to California would reduce or reverse the flow between the Northwest and Montana-Wyoming, and increase the flow from Montana-Wyoming to California on the eastern lines.

If the transaction from Montana-Wyoming to the Northwest used a scheduled or contract path directly joining the two areas and not including California, the 420 MW flow not using that path is a clockwise loop flow. WSCC has pursued use of flow control devices called phase shifting transformers to reduce loop flows.

SOURCE: Casazza-Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access*, OTA contractor report, March 1988.

3. improving the control of real power flows on a network,
4. decreasing the response time of generators and transmission line switching, and
5. adding new lines.

Figure 4-5—Western Interconnected System



SOURCE: Casazza Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access*, OTA contractor report, March 1988.

Table 4-7 shows how these options relate to the types of system limitations.

The costs of increasing transmission capability are site-specific, depending on a host of factors such as terrain, system configuration, type and age of equipment being upgraded, etc. Often, a transmission line or generator being upgraded must be temporarily taken out of service. Lost use of the equipment creates a highly site-specific cost, particularly significant in cases where a line being upgraded is in heavy use. As a result, generalizing about cost and performance is difficult.

Meaningful estimates of the benefits of options to increase transfer capability are even more difficult to develop. There are several reasons. First, most changes will affect not only transfer capability but the system operating economics and system reliability as well. Developing a meaningful combined measure of performance that trades off between these factors has proven elusive. Second, the impact of any measure of system transfer capability, operating economics, and reliability is highly site-specific. The impact of a new transmission circuit in a remote part of Nevada and an identical circuit parallel to an

Table 4-7—Technologies To Increase Transfer Capability

Remedies to individual line constraints
- *Voltage uprating*
  - Tower extensions
  - Upgrading insulators
  - Upgrading terminal equipment (circuit breakers, relays, transformers)
- *Current uprating*
  - Dynamic conductor rating
  - Sag assessment and monitoring
  - Restringing (live-line restringing)
  - Changing operating standards
- *Tower design and new lines*
  - Conversion to multiple circuit towers
  - High-voltage direct current lines

Remedies to steady state system operating constraints
- *Control of load division*
  - Phase angle regulators
  - Series reactance and capacitance
  - System reconfiguration
  - HVDC control features
  - Redispatch of generation
- *Reactive power management techniques*
  - Shunt or series capacitors
  - Shunt reactors
  - Static VAR compensators
  - Synchronous condensers
  - Generators as VAR sources

Remedies to contingency security and stability constraints
- *Improving generation response controls*
  - Generator tripping and fast runback
  - Fast valving
  - Braking resistors and load switching
  - Advanced excitation systems and stabilizers
  - Transient excitation boost
- *Improving transmission response controls*
  - High-speed reclosing and reducing clearing time
  - Rapid adjustment of network impedance
  - Fast acting phase angle regulators
  - Sectionalizing (adding switching stations)

SOURCE: Adapted from Power Technologies, "Technical Background and Considerations in Proposed Wheeling, Transmission Access, and Non-Utility Generation," contractor report prepared for the Office of Technology Assessment, March 1988, p. 6-2.

existing line in the Northeast are considerably different. Also, the impacts vary over time, as loads change, and as available resources and their costs change.

The following is a summary of some of the approaches to increasing transfer capability. For a more comprehensive, technical description of solutions to increased transfer capability the reader is referred to *Technical Limits to Transmission System Operation*, published by the Electric Power Research Institute.[21]

Increasing the Capacity of an Existing Line

Increasing Voltage

Since the acceptable voltage range for operation of transmission circuits without flashovers is determined primarily by the line's equipment and design, the opportunities are limited to changing equipment. Transmission towers can be extended and insulators upgraded to increase the spacing between the conductors, towers, and ground. Terminal equipment such as switches, circuit breakers, meters, and transformers will also need to be upgraded to the higher voltage ratings.

Increasing Current Ratings

One method to uprate the current carrying capacity of a line is to simply increase the allowed temperature rise, and thereby increase the amount of current flow allowed. This method has a very low initial cost. However, there may be some reduction in equipment lifetime.[22]

A related technique is to use *dynamic line ratings*. Normally, a line's current ratings are based on imprecise and conservatively forecast estimates of ambient weather conditions. Using dynamic line rating, the actual ambient weather and the temperature and sag of the conductor are measured, permitting the line to operate closer to its physical limits on cool or windy days. Dynamic line rating adds some increased operational complexity and increases the variability of transfer capability over time.

Resagging a line to raise it higher off the ground may also allow increased current flows if the line is constrained by excessive sagging. This has been done in some cases while the line is still in service. Another option is restringing—installing a larger conductor with higher current ratings. This may require reinforcement of the existing towers but costs considerably less than adding a new line.

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[21] Power Technologies, Inc., *Technical Limits to Transmission System Operation*, EPRI EL-5859, June 1988.

[22] *IEEE Standard for Calculation of Bare Overhead Conductor Temperature and Ampacity Under Steady-State Conditions*, ANSI/IEEE Standard 738-1986, 1986.

Tower and Circuit Reconfiguration

Voltage and/or current limits may also be extended by more extensive changes in line circuit and tower design. If tower strength permits, a single wire line may be replaced by a bundle of two to four wires, raising both thermal and corona limits. In addition to restringing circuits already in place, it may be possible to string another separate circuit. Original towers may already have space for new circuits in anticipation of future need. A new possibility under investigation is either to restring an old AC line as a new HVDC line, or to add a new HVDC circuit in combination with an existing AC circuit as space permits.

Controlling Real Power Flows

As explained above, network transfer capability is limited by the most constrained line in the system, so any method which can control or alter flow in the network may have major benefits. There are number of methods which can be used to control network flow, but this is done by changing the network characteristics in different places, rather than by changing the rules of network flow.

The first and foremost technique for controlling network flow is off-economic dispatch of generating units. By generating power at particular network locations, rather than in economic order, network flow can be kept with reliability and capacity limits.

A second practical, inexpensive, and common method is to alter the network itself by disconnecting one end of a constraining (typically lower voltage) line. The line then carries only the customer load it serves. This method may also be used on one of two parallel lines under low load conditions, so that increased loading on the remaining line is better matched to the VAR compensation present. In both cases, the benefit is purchased at the cost of lower reliability, as fewer paths between generation and loads remain.

Phase shifting transformers (also called phase angle regulators) change the phase angle between input and output by advancing or retarding the relative time at which the input and output sine wave voltage peaks occur. By doing so these devices act as a valve which can increase or decrease the flow of power on a line. Phase shifting transformers have not been widely used due to past problems with reliability. They also have the undesirable side effects of increasing reactive power losses. There is some hope that future developments in high-power electronics will produce devices that can be used with phase shifting transformers to control individual line flow (discussed below).

A technique called Rapid Adjustment of Network Impedance (RANI) can be used to continuously vary VAR compensation to maximize power flow on a single line. It can also be used to vary the impedances on one or more lines in such a way as to control power flow on the network. Because this control is achieved by varying line impedance, there is the possibility that it will be paid for in increased line losses. The cost of such line losses must be balanced against improved reliability, reduced need for new power lines, and other benefits.[23]

High-voltage direct current (HVDC) power lines are used for high-power, long distance lines and as asynchronous connections between the three main interconnected regions of the United States. Through application of high-power thyristors used to convert AC power to DC and back again, the voltage and hence the power transfer of the DC line can be directly controlled, possibly enhancing stability as well. While it is currently uneconomic to use DC lines for such power flow control, research continues on multiterminal DC lines and improving the cost and capacity of high-power semiconductors. HVDC appears to be the single most powerful method of direct flow control in the battery of options and with economic feasibility could have a major impact on the industry.

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[23] The Bonneville Power Administration is experimenting with RANI, with a preliminary study showing it to compare favorably with mechanically switched shunt capacitors, static VAR compensators, and mechanically switched series capacitors on the Pacific AC Intertie in providing transient support and damping and post-disturbance support and stability. In one configuration, loop flow was reduced 43 percent (348 MW) at the cost of 68 MW incremental losses. (Personal communication with Mr. Dean Perry of BPA, July 1988).

Controlling Reactive Power and Voltage

Increasing the availability and control of VAR supplies on the system is one approach to alleviating voltage-related transmission limits.[24] Generators are one common source of VARs as well as real power. Capacitors may be installed at various points to increase the available supply of VARs. The capacitors can be designed to be switched in and out of operation, allowing operators to control VAR supplies. Synchronous condensers and static VAR compensators may also be installed on transmission lines to provide a controllable source of VARs. Inductors may be connected in shunt with the line in specific instances. Series connection is rare and used to control excess current in short circuit conditions. Another technique typically used to control VAR flows is to control the VAR output of generators, just as real power is controlled.

Increasingly, methods are being developed for operation and control systems to use computer load flow models (called optimal power flow models) to simultaneously dispatch both VARs and real power. It is anticipated that the future will see more applications of these methods. The cost of implementation will include metering and communication and control equipment as well as new software.

Stability Response

A utility can increase its transfer capability by shifting its reliability policy from the preventative mode of operation to the remedial mode. There are numerous special protection schemes being developed and applied. Generation response options generally increase the ramp rate at which a generator can increase or decrease its output or temporarily increase its peak output. These options may increase maintenance costs by increasing operating stresses.

Generator "tripping," "fast runback," and "fast valving" systems are generator control schemes designed to rapidly reduce power fed into the grid while continuing to keep the unit on line and available. Increased output from generators can be obtained by temporarily turning off auxiliary plant equipment at the generating stations. A 10-percent increase in output may be temporarily obtained using these measures. However, operating power plants in this way may reduce equipment life or increase the risk of failure.

These methods have been used in specific cases but have not been widely applied to date. They require careful study and application if they are to achieve the same level of system reliability as achieved by the defensive scheduling techniques.

Future Trends

A wide variety of techniques for increasing transfer capability are in use and under development in the United States. There are some developments which may have significant long-term effects on system operation and transfer capability. These include developments in high-power semiconductors; ongoing improvements in computing and data processing capabilities; and, in the very long term, possibly even superconductivity.

In general, developments in these areas will have gradual but increasing impacts. For example, high-power semiconductors are already leading to fast, nonmechanical switching of VAR control devices. Further developments will lead to improved reliability and speed for phase shifting transformers and other devices, before direct switching of high-voltage alternating current (HVAC) lines becomes possible.

High-Power Semiconductors

With few exceptions, present-day power systems use mechanical control devices. Mechanical circuit breakers, relays, switches, tap changing transformers, and generator controls use moving contacts to close or open circuits, and are therefore limited in the speed and number of times they can operate. These limitations mean that power systems are neither as responsive nor as reliable as may often be desired.

Developments in high-power semiconductors to allow electronic rather than mechanical control promise to improve the performance of the power system in significant and pervasive ways. This is not a sudden revolution, but a continuing trend that has already lead to static VAR compensation and HVDC transmission lines. However, recent research has dramatically expanded the prospects for a range of future uses.[25]

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[24] See, for example, Scientific System, Inc., *Optimization of Reactive Volt-Ampere (VAR) Sources in System Planning*, EPRI EL-3729, Electric Power Research Institute, November 1984; and University of Washington, *Reactive Power Management Device Assessment*, EPRI AP-5210, Electric Power Research Institute, August 1987.

Controlling Power Flow

There are several possible applications of high-power semiconductors to the general area of controlling power flows.[26] As described above, there are many means of relaxing power transfer constraints, and several of them have the opportunity to be significantly improved by the use of high-power semiconductors. Static VAR Compensations and Rapid Adjustment of Network Impedance (RANI) are both early applications of high-power semiconductors (thyristors). Both methods rapidly and continuously vary the amount of shunt or series reactance present to control the total line impedance. Higher power semiconductors will have applications to phase-shifting transformers and variable voltage tap-changing transformers.

Use of high-power semiconductors as switches, or resettable fuses, to directly reconfigure the actual network will require very high voltage and current capabilities. Switches that can handle such high voltages and currents economically have not yet been developed, but the prospect is within sight. The speed and control of switches that can turn on and off every cycle (or more often) without wearing out will make remedial reliability methods more practical and economic.

High-power semiconductors are currently used on HVDC power lines to convert AC power to HVDC and back again. The power thyristors used in this conversion are sufficiently expensive that HVDC power lines are only practical for lines which are long enough to bear the high terminal cost or as interconnections between asynchronous systems. Lower cost and higher capacity semiconductors will make shorter DC lines economically practicable and allow multiterminal HVDC lines, instead of the two terminal lines now used. Because the conversion voltages at both ends of a line can be controlled, HVDC transmission allow essentially complete control of network flow.

Power Control of New Energy Sources and Storage

In addition to increasing network transfer capability and reliability, high-power semiconductors will play a crucial role in power conversion and conditioning for new power sources and energy storage systems. Energy sources such as photovoltaics and fuel cells produce relatively low voltage DC power. It is necessary to convert this power to AC in order to connect the generating unit to the grid. Wind power plants already produce AC power, but the mechanical governors needed to regulate frequency are liable to stress, reduce reliability, and limit the maximum power available from the wind. Solid state power conversion can be used to let the wind turbine generate as much power as possible, convert the variable frequency power to 60 Hz AC, and also supply VARs to compensate for the natural inductance of these generators. In addition to generation, various proposed energy storage methods require conversion of AC to DC power, and back again. Whether as basic as batteries or as esoteric as superconducting magnetic energy storage, higher power semiconductors will play a key role in making the necessary energy conversion reliable and efficient.

One key to increasing semiconductor power capability is the development of high-purity silicon devices which can handle large currents and voltage with losses low enough that device temperature is reasonably limited. One such device being developed is the metal oxide semiconductor controlled thyristor (MOS-CT). These devices are light fired, or optically triggered, by a laser diode either directly or via fiber optics. Unlike conventional thyristors, these devices can be turned off as well as turned on during each half cycle. More importantly, these devices can combine a microprocessor on the same chip as the power semiconductor to produce integral intelligent control of the high-power switch. The thyristors may be stacked in parallel or series to increase current and voltage and this stacking may be done either on a single chip or by stacking chips together.

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[25] Steitz & Associates, *Materials and Devices for Power Electronic Applications*, EPRI AP/EM/EL-5470, Electric Power Research Institute, March 1988.

[26] N.G. Hingorani, "High Power Electronics and Flexible AC Transmission System," *IEEE Power Engineering Review*, July 1988, pp. 3-4.

Development of high-power semiconductors is currently underway as a joint effort between industry and government. The Department of Defense is interested in high-power switching required for Strategic Defense Initiative (SDI) applications, and the National Aeronautics and Space Administration (NASA) is also interested in civilian space-drive applications. In October 1987, EPRI opened the Power Electronics Applications Center in Knoxville, Tennessee. This center and a series of yearly conferences are intended to promote industrial and consumer end-use applications of power electronics, rather than basic research. This effort reflects the belief that recent power electronics developments have created opportunities and that applications have lagged their potential.

Research is being conducted primarily by General Electric with some work also being performed by Westinghouse. The work is being funded by the Army (under SDI), Navy, Air Force, NASA, and EPRI. Current funding is about $3.5 million per year, with about $2.5 million being spent upon hardware/device development and about $1 million (from DARPA) being spent on materials development. Total government spending is estimated to total 10 to 40 million dollars, excluding industry investment.

Single semiconductor devices rated up 20 kV and a few thousand amps are envisioned within the next 10 to 30 years which will meet utility needs with low losses, low cost, and fast switching capabilities. Such capabilities make it likely that delivered power will flow through high-power semiconductors several times before reaching the customer.

Improving Computer Capabilities

Continuing trends in data processing and computing capabilities have widespread applications in power system operations and planning.[27] Expert systems and artificial intelligence continue the trend towards increasing computer applications in the utility industry and are properly a subset of a wide array of advancing modeling and computer analysis capabilities.[28]

Expert systems essentially codify a subject or system of knowledge that is too large or esoteric for the end user, into software form. The codified rules then guide the user interactively by requesting data and making suggestions. Some of the varied applications for improved computing capabilities include the following.

System Engineering and Planning

System planners use many specialized computer applications for such diverse activities as:

- forecasting and modeling loads,
- selecting generation expansion plans,
- selecting transmission capacity expansion plans,
- examining reliability of systems,
- investigating system stability, and
- real and reactive power flows resulting from systems changes.

Many of these applications are computationally challenging and are continuing to benefit from the expanding abilities of both computer hardware and software.

Control Center Operations

As in system planning, many specialized computer applications are used in control centers. Faster and more powerful hardware and software allow improved monitoring, analysis, and modeling of system conditions as they change. Areas of application include:

- real-time load flow models allowing optimization of VAR dispatch and optimization of power transfers,
- improved monitoring of thermal conditions and voltages on transmission lines allowing dynamic line ratings,
- improved response to system emergencies, and
- real-time assessment of contingency security.

Transmission and Distribution Automation

The current transmission and distribution system is largely mechanically controlled and operation is confined primarily to generation dispatch and emergency response. Development of more flexible AC transmission controls, increased dependence on remedial reliability responses, and distribution automation (including load shedding control) are trends which will complicate operation of the transmission and distribution system. These trends, which should bring improved reliability and economy, make use of the advances in communication and data processing capabilities.

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[27] See for example, "Special Issue on Computers in Power System Operations," *Proceedings of the IEEE*, December 1987; or Carlsen & Fink Associates, Inc., *Integrated Power System Analysis Package: Scoping Study*, EPRI EL-4632 vols. I and II, Electric Power Research Institute, July 1986.

[28] University of Washington, *Development of Expert Systems as On-Line Power System Operational Aids*, EPRI EL-5635, Electric Power Research Institute, February 1988. Carnegie-Mellon University, *Artificial Intelligence Technologies for Power System Operations*, EPRI EL-4323, Electric Power Research Institute, January 1986.

Power Plant Diagnostics and Monitoring

Advances in power plant diagnostics and control systems allow more reliable and efficient operation at the price of complexity. Expert systems can assist the operator in a range of ways from finding problems before component failure, to helping determine ramp rates and timing that will optimize the trade-off between heat rate and plant life.

Operator Training and Simulation

In addition to helping run a generating plant, expert systems can also be used for initial and ongoing training of operating personnel. Such systems can be useful in practicing responses to extreme situations which rarely occur, especially in nuclear plants. Nuclear plants typically have a simulator operating room for such purposes, but expert systems can assist in organizing, recognizing, and responding to data instead of just presenting a scenario.

Superconductivity

Superconductors will have a number of obvious and important possible applications in the utility industry when further development makes them practical. These applications include superconducting generators, transmission lines, magnetic energy storage, and large inductors.

These possible uses have been recognized for a long time and have been researched to a limited extent using older, conventional low-temperature metal superconductors. The recent discovery of ceramics which superconduct above the temperature of liquid nitrogen (77° K) raises the hope of much reduced costs and wider applications. The rate and extent of superconductor applications depends upon how fast and how far it is possible to push three interrelated limits to superconductivity: critical temperature, magnetic field, and current density. The critical temperature is the best known limit and determines the extent of thermal losses (which would be important in applications such as transmission lines). The current density limit is also important for power applications, since it is key in determining size and cost. Cost limitations will probably be based primarily upon fabrication costs and operating costs.

The most likely actual early use appears to be in energy storage.[29] Economic storage of electricity using superconducting magnets would be revolutionary indeed. The structure and operation of the utility business is built on the fact that electricity cannot be stored. Storage options to date include pumped hydro, compressed air storage, and batteries, but are site limited, inefficient, and/or expensive. Energy storage would allow supplying electricity at a relatively flat, constant rate to meet the changing daily load curve, which would in turn allow use of efficient, base-load plants only. Reliability, system control, and the use of new energy sources (such as photovoltaics) would all benefit enormously.[30]

The difficulties will include cost, refrigeration, and enormous magnetic stress on brittle ceramic superconductors. On a smaller scale, energy storage may be used to improve system stability and reliability.

Another possible application is in generators, where use of superconductivity would produce higher magnetic fields, smaller size, and lower losses. Because of the high efficiencies of conventional generators (greater than 98 percent), gains would be relatively small. Preliminary designs and testing of prototypes have already been made for such generators, using lower temperature metal superconductors.[31]

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[29] U.S. Congress, Office of Technology Assessment, *Commercializing High Temperature Superconductivity*, OTA-ITE-388 (Washington, DC: U.S. Government Printing Office, June 1988), p. 161.

[30] For a discussion of the more general benefits of storage, see Electric Power Consulting, Inc., *DYNASTORE—A Computer Model for Quantifying Dynamic Energy Storage Benefits*, EPRI AP-5550, Electric Power Research Institute, December 1987.

[31] U.S. Congress, Office of Technology Assessment, op. cit., footnote 29.

Transmission lines are a possible later use, but not necessarily as attractive as they might first appear. Although the line would have no resistance, this would have to be balanced against cooling losses, total cable and burial costs v. an overhead line, and (presumably) reduced right-of-way requirements. More importantly, we have already seen that pure resistance losses are not the constraining limits to power transfer, particularly for medium and long lines. Superconducting cables will not relax synchronous stability or voltage support constraints. HVDC circuits would benefit much more from superconducting lines but AC/DC conversion equipment costs will still limit use to long lines until the price of high power semiconductors drops. In either case transmission losses typically total in the neighborhood of 1 to 3 percent (up to 6 percent for systems with long lines), so any improvements will not be revolutionary. Reduced siting and environmental impact of buried superconducting lines may be major forces even if purely economic benefits are marginal.

Some utility applications of superconductivity have already been designed and tested. These include:

- A 1982 test of superconducting transmission cable proved a 2,000 MW capacity for a 16 inch, liquid helium cooled test cable. This test was performed by Brookhaven National Laboratory in conjunction with EPRI.
- A superconducting magnet installed and tested by the Bonneville Power Administration for use in controlling transmission line fluctuations at its Tacoma substation. This reliability application of magnetic energy storage is likely to precede application of large-scale energy storage for flattening daily load curves.

Chapter 5

Technological Requirements and Performance Under Increased Competition

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Chapter 5

Technological Requirements and Performance Under Increased Competition

INTRODUCTION

Proposals for increasing power industry competition raise challenging questions of technical feasibility and cost. What technological requirements does competition raise? What would meeting those requirements cost, and how would reliability be affected? What is required to make a competitive proposal workable?

The answers depend on the type of competition envisioned. The five scenarios of chapter 3 present widely varying visions of power industry change, each with its own specific technical questions. While each scenario is unique, they share two fundamental competitive changes:

- expanded generation market—more companies allowed to enter and compete in supplying electricity; and
- expanded transmission access—a widened avenue of exchange between competing generators and purchasers with the involvement of the local utility restricted to transmission services.

Both types of change involve unbundling, or separating, of generation from transmission to different degrees.

Power industry competition may take a variety of forms depending on how and to what extent increased supply competition and expanded transmission access are implemented. For example, supply market competition may unbundle all generation from transmission (scenarios 4 and 5). Alternately, competition may be limited to some (scenarios 1 and 2) or all (scenario 3) new generation only, leaving existing generation under the ownership and control of integrated utilities. Competition in new generation may be limited to certain suppliers, such as facilities qualifying under the Public Utility Regulatory Policies Act (PURPA), or may include other independent power producers as well as new utility generation.

Similarly, alternatives for expanding transmission access range from encouraging further voluntary wheeling (all scenarios) to mandating wheeling among utilities (scenarios 2, 3, and 4) or for large retail customers (scenario 2) to entirely unbundling transmission from both generation and distribution so that all power is wheeled power (scenario 5).

Chapter 5 examines the technical feasibility and costs of the changes that will be required by increasing competition. It also summarizes the general technical and economic impacts of competitive change in the electric power industry. Next are analyses of the challenges of increasing the number of separate bulk power suppliers and those posed by expanded transmission access. This is followed by a review of the cost and performance of the current utility structure, examining where economic performance of industry changes may lie. The last section summarizes the technical issues raised by each of the five scenarios discussed in chapter 3.

In this chapter, the impacts of competition are viewed from a system coordination perspective. As described in chapter 4, all the individual generation and transmission components of a power system must be coordinated. No matter what form competition takes, no matter what the extent of expanded markets, some system will be required to coordinate planning and operation of the individual pieces. Even if the ownership of generation, transmission, and distribution is entirely separated (scenario 5), there still has to be a highly sophisticated system to coordinate planning and operation.

Throughout this chapter, it is assumed that the competitive changes should not result in degradation of the reliability of a power system. This assumption is necessary to keep separate the consequences of competition from other unrelated decisions. For example, service reliability could be reduced deliberately to lower the cost of service or to better match consumer preferences under any scenario. However, by accepting reduced reliability in one scenario but not in another, comparisons of the effects of competitive measures on planning and operating procedures and on physical system requirements would not be meaningful.

OVERVIEW OF TECHNOLOGICAL IMPACTS

The technical feasibility of increased competition depends largely on developing new approaches to coordinated planning and operation of the bulk power system. Defining workable institutional arrangements between the participants in the power system is a fundamental requirement. Implementing these new institutional relationships may also require adding some new physical facilities and improving analytical capabilities.

As discussed in chapter 4, a power system is a vast, complex machine composed of many interacting generators, transmission lines, and distribution systems. A reliable, economic supply of electricity requires carefully coordinated operation and planning of the individual generating units and transmission lines that comprise the bulk power system. Coordinating the bulk power system involves three main functions:

- following changing loads to balance the supply of power with ever-changing demand,[1]
- maintaining reliable operations, and
- coordinating power transactions between interconnected systems.

Typically these functions are performed in a way that minimizes cost. Many operating and planning procedures are involved in performing these functions (see table 5-1). The procedures range from the immediate (e.g., regulating frequency) to the long term (e.g., planning and constructing needed new supplies) and reflect electricity's complex physical laws.

In today's power systems, the responsibilities for coordinating planning and operation belong to a single utility or group of cooperating utilities.[2] Current utility approaches to planning and operation assume relatively centralized control and decision-making, with a system-wide objective of providing reliable and economic service. The control areas formed by one or more utilities are responsible for regulating frequency and voltage, and coordinating power interchange. They have control over generation and transmission components needed to meet that responsibility. Unit commitment and maintenance scheduling are the responsibilities of the utility owning the equipment, or the utility's power pool. Planning new supply resources and transmission facilities is typically a utility responsibility, often performed with considerable regulatory oversight and review by the North American Electric Reliability Council (NERC) region and local pool to assure reliability.

Unbundling generation and transmission creates a more complex planning and operating environment by defining new rights and responsibilities for suppliers, purchasers, and transporters of power. The changes modify basic operating and planning assumptions by raising the number of separate players, each seeking their own economic benefit.[3] Unbundling creates a gap between the entity responsible for coordinating the overall power system and the ownership and final control over the system components.[4] As the number of players grows and unbundling increases, control and decision-making authority is increasingly dispersed. Operations will increasingly depend on individual agreements between generators and purchasers (and in some cases, transporters), and will not necessarily

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[1] This balancing involves both active and reactive power.

[2] Note that coordinated operating and planning neither implies nor requires ownership by a single entity or a small group. For example, in the New England Power Pool (NEPOOL), around 100 separate utilities coordinate their planning and operation, sharing in the resulting benefits. In addition to the multilateral pooling agreement, there are several hundred bilateral arrangements between NEPOOL members that specify how overall benefits are allocated.

[3] Note that it's not necessary to greatly increase the number of separate players to greatly modify basic operating and planning assumptions. For example, a vertically integrated utility could be separated into one generating company and one transmission/distribution company (possible in scenario 4). In this case, the number of players increases by only one. However, the resulting interactions between the two companies would be all new and substantially different from what had existed before with a single integrated company.

[4] Recall that in the scenarios as discussed in chapter 3, as a practical matter responsibility for ensuring adequate supplies remains with those closest to the customers, i.e., the companies performing distribution or the customers themselves under retail wheeling. This is true no matter if all supply is competitive and owned separately from the transmission and distribution functions or if a competitive market supplies only a portion of new capacity needs for vertically integrated utilities. Similarly, responsibility for coordinating all system components must rest largely with the companies performing transmission, since it is the transmission network which provides the link between components.

Table 5-1—Operation and Planning Functions

Function	Purpose	Procedures involved
Following load		
Frequency regulation	Following moment-to-moment load fluctuation	Governor control Automatic generation control (AGC) and economic dispatch
Cycling	Following daily, weekly, and seasonal cycles (within equipment voltage, power limits)	AGC/economic dispatch Unit commitment Voltage control
Maintaining reliability		
Maintaining security	Preparing for unplanned equipment failure	Unit commitment (for spinning and ready reserves) security dispatch Voltage control
Maintaining adequacy	Acquiring adequate supply resources	Unit commitment Maintenance scheduling Planning capacity expansion
Coordinating transactions	Purchasing, selling, and wheeling power in interconnected systems	AGC/economic eispatch Unit commitment

SOURCE: Adapted from F. Mobasheri, Southern California Edison, letter to OTA, May 13, 1988.

focus on overall power system needs. This may affect both reliability and economy.

For example, selecting which supplies to commit and dispatch is currently performed centrally by integrated utilities at energy control centers. The objective is to minimize operating costs (i.e., economic dispatch and scheduling) constrained by reliability requirements and equipment limits. With competitive generation or retail wheeling, the selection is further constrained by the arrangements between supplier, transporter, and purchaser. As a result, in some instances an unschedulable supply may operate even when lower operating cost resources are available.

With increased unbundling, new institutional arrangements must accommodate both the changing abilities and economic incentives of power system participants and the technical characteristics of electricity. The new operating and planning procedures must specify priorities for the use of constrained facilities, information flows between parties, and incentive and enforcement schemes. As in today's power systems, the arrangements may include formal contracts between the parties as well as less formal agreements on standards and procedures. Operating agreements and standards may be developed through multilateral organizations (such as NERC and the Institute of Electrical and Electronics Engineers) or bilaterally. In addition to the agreements between suppliers, transporters, and purchasers of power, other arrangements must specify the role of regulatory agencies and other interested institutions.

As unbundling increases, bilateral and multilateral contracts will be increasingly important instruments to communicate needs and define obligations of suppliers, transporters, and purchasers of power. By specifying prices and performance, including penalties for failure to perform, contracts can help ensure that competitive supplies meet power system needs and mitigate uncertainty for both parties. However, contracts may have some shortcomings when compared to arrangements within a single organization, as in a vertically integrated utility. For example, given the tremendous uncertainty in the power industry, anticipating all the terms and contingencies which a contract should cover requires extensive effort. Even with carefully crafted and flexible contracts, unexpected events outside the scope of the contract may occur.

Implementing new arrangements may require some changes in physical facilities. New monitoring and communication equipment may be needed to track and control the new unbundled transactions occurring. Additional transmission capacity may be required as the pattern of loads and supplies changes. Additional reserves of generation and transmission capacity may be needed in the face of increased uncertainty about how well the new institutional arrangements will perform. Alternately, if competition produces improved performance of generating units, reduced reserve requirements may result.

New or improved analytical methods may be needed both in developing and implementing new procedures. Many attributes of power systems central to planning and operation are not easily quantified. For example, the availability of additional transmission capacity at any moment is challenging to calculate and somewhat subjective. The value of such generation characteristics as fuel diversity and level of dispatchability is similarly hard to quantify. And as noted by Edison Electric Institute, "In virtually every form of coordination sale, there are subjective determinations and uncertainties which are generally not susceptible to simple quantification for purposes of regulatory adjudication. Many of these uncertainties relate to the potential impacts on system reliability of a particular transaction."[5] As the functions currently performed by integrated utilities are unbundled and provided by different parties, accurate measures of the performance of each party and calculation of the cost or value of their contribution to the power system will become increasingly important. Evaluating performance is essential for developing prices and priorities, a prerequisite for a functioning market.

There has been little analysis of the reliability or economic impacts of competitive proposals. The past decade brought some competitive experience to the industry.[6] PURPA advanced new opportunities for qualifying facilities (QFs) to generate power using untraditional technologies using cogeneration, renewables, and waste products. Some utilities and State regulatory agencies have gained considerable experience in integrating these QFs. A few proposals for non-QF independent power producers using more traditional generating technologies have also been advanced. One is slated for operation in 1989 (see box 5-A on the Ocean State Power Project.) A few experiments based on more flexible pricing have given some utilities expanded transmission access. Analyses of the cost and performance are still to come.[7] These competitive changes continue to play a prominent role in the evolution of the industry. However, many current competitive proposals reach well beyond the experiences gained in the past decade. The lack of experience in widespread wheeling and in competitive generation of unrestricted size, type, location, and penetration results in substantial uncertainty over how well the system would work under the scenarios.

How suppliers, purchasers, and transporters of power will respond to any competitive proposal is speculative. It is this individual behavior and how it is coordinated, however, that determines the real feasibility, reliability, and economic impact of increased competition in the electric utility industry. The costs and benefits of increased competition depend not only on the cost of developing and implementing the new procedures but on how those procedures affect the efficiency of the current utility structure and encourage improved performance.

This study has identified no insurmountable problems of technical feasibility with any of the scenarios, although there are some substantial institutional challenges of developing new planning and operating arrangements. The ease or difficulty of implementing the institutional changes to meet technical requirements is necessarily speculative. For the scenarios with incremental competition in generation and controlled transmission access (scenarios 2 and 3), some view the institutional changes as relatively easy to develop; others believe there will be considerable difficulty. However, growing experience indicates that some forms of scenarios 2 and 3 are feasible. Major system-wide changes raise considerable uncertainties and risks to reliability and economy. Separating all generation from transmission (in scenarios 4 and 5) raises the greatest risks. Both reliability and economy could be greatly reduced in the potentially long time required to experiment and develop new procedures for such extensive changes.

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[5] Edison Electric Institute: FERC Docket RM85-17-000 (Phase I) Comments of Edison Electric Institute, Aug. 9, 1985, p. 10.

[6] See ch. 6 for more discussion of State and utility experiences.

[7] These include the Western Systems Power Pool, in operation from 1987 through 1989; and its precursor, the 2-year Southwestern Experiment which ended in 1985 (see boxes on the Western Systems Experiment, and the Southwest Experiment later in this chapter).

Box 5-A—A Partly Independent Power Producer: The Ocean State Power Project

In August 1988, the Federal Energy Regulatory Commission (FERC) accepted a power sales agreement for the Ocean State Power Project (OSPP) in Rhode Island.[1] OSPP will use a single 235 MW natural gas-fired combined cycle unit, with a possible second unit at a later date. It is the most advanced example of a large independent power producer (IPP) that is not a qualifying facility under the Public Utility Regulatory Policies Act. While only partly independent of utility ownership, OSPP is one model of a non-QF independent power producer.

Ownership

OSPP is a partnership of private developers and electric utilities. Fifty percent interest in the plant is divided among several affiliates of the electric utilities purchasing some of the power output.[2] They are:

- 25 percent Eastern Utilities Associates, parent of Montaup Electric Co.;
- 20 percent Narragansett Energy Resources, affiliate of New England Power Corp.; and
- 5 percent NECO Power, Inc., subsidiary of Newport Electric Corp.

A subsidiary of TransCanada Pipelines has a 40 percent interest. (Another TransCanada subsidiary is OSPP's natural gas supplier.) The remaining 10 percent interest is held by affiliates of J. Makowski.

According to FERC, with respect to the above utilities, OSPP would not qualify as an IPP.[3] However, a substantial portion of OSPP's power will be sold to Boston Edison, which has no financial interest. With respect to Boston Edison, then, OSPP would qualify as an IPP.

Operation

Although not owned primarily by electric utilities, OSPP will operate as a traditional utility generating unit. In New England, the New England Power Pool performs economic dispatch based on generating unit operating costs and system operating requirements. Because of the high operating efficiency of OSPP's combined cycle unit, the project developers expect that the plant will generally operate as a base-load unit.[4] Plant operation is expected to begin in 1990.

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[1] *Ocean State Power*, Order Accepting Amendments to Power Sales Agreements, FERC Docket No. ER88-478-000, Aug. 19, 1988. Also, *Ocean State Power*, 38 FERC 61,140 (1987).

[2] *Electric Utility Week*, May 23, 1988.

[3] *Ocean State Power*, Order Accepting Amendments to Power Sales Agreements, FERC Docket No. ER88-478-000, Aug. 19, 1988, footnote 28.

[4] J. Makowski and C. Riva, "Gas Fired Electricity: The Ocean State Power Project," *Energy Technology XIII: Energy in Transition*, Government Institutes, Inc., March 1986, pp. 189-198.

INCREASING SUPPLY COMPETITION

This section examines the effects of extending current coordination systems to an increasingly competitive supply market. The challenges of increased wheeling are left to the following section.

In today's power systems most generation is owned and operated by vertically integrated utilities which also own and operate the transmission and distribution systems. However, **there is already a moderate and increasing amount of competitive supply in use employing a variety of generation technologies and forms of ownership**. Competitive suppliers of electricity include:

- PURPA QFs, either cogenerators or small power producers using a variety of untraditional supply technologies and fuels;
- non-QF independent power producers (IPPs);
- utilities with surplus capacity; and
- foreign electricity suppliers, most notably Canada.

Developers of demand management programs may also play a role in increasing competition.

The physical performance capabilities of competitive suppliers may present both challenges

and opportunities to coordination. For example, some cogeneration units may be inherently less responsive to controls than a typical utility generator. However, those same cogeneration units may also bring the planning and operating benefits of reduced construction lead time, lower capital and operating costs, higher availability, and smaller unit size. The physical characteristics which determine the value of a generator are diverse, including such factors as size, location, construction lead time and cost, ramp rates, dispatchability, voltage and VAR output, fuel type, operating efficiency, and reliability, as described in chapter 4.

Modern planning and operation systems have a demonstrated ability to integrate a wide variety of supply technologies, exploiting the advantages of each. Whether that ability can be extended to coordinate an increasingly competitive supply market depends on two factors. First, does the generation technology used by competitive suppliers raise unique technological challenges? For example, is the equipment used in a cogeneration or independent power facility inherently less responsive to controls than typical utility generation? Second, do the arrangements between the competitive suppliers and purchasers provide the appropriate information and control to coordinate generator operation and planning?

Challenges caused by most generation equipment should be relatively minor or nonexistent. In fact many competitive suppliers—particularly IPPs, utilities with surplus low cost capacity, and foreign imports—may use traditional generating technologies (see box 5-A). The performance capabilities of even those competitive suppliers using cogeneration and less traditional technologies and fuels often produce power with characteristics within the wide range commonly found in today's utility generation equipment.[8]

Some generating units, notably those using wind or solar power and in some cases, cogeneration, have variable power output, unlike traditional utility resources. For example, power may vary regularly with the sun's daily cycle or may change suddenly as clouds block the sun, winds gust, or industrial facilities change steam requirements. These technologies, often grouped together as dispersed sources of generation (DSGs) have been widely used as QFs under PURPA. The technical literature has discussed many aspects of the growth of DSG plants on utility system planning and operation.[9] Many technical problems of the relatively small-sized DSGs are due to the combined effects of the operating characteristics of these plants and the fact that they are often connected to the utility network at distribution voltage levels.

Conservation and load management may also play a role in more competitive supply markets. Many U.S. utilities actively promote conservation and load management as alternatives to traditional supplies. While the cost and operating characteristics of conservation and load management options vary widely, many have some operating characteristics similar to supply resources.[10] For example, interruptible rate programs, which allow utility dispatchers to turn off customer loads at peak periods with little notice, have characteristics similar to peaking generator units. Some conservation programs have characteristics similar to base-load resources. As with DSGs, when properly planned and integrated into a power system, conservation and load management should cause no operating problems.

Although the performance capabilities of technologies used by most competitive supplies raise relatively few difficulties, new arrangements for coordinating planning and operation are required. Unbundling generation from transmission requires modifying current operating and planning procedures, including developing new pricing arrangements and analytical capabilities. Most experience to date has come from implementation of PURPA, in developing the pricing arrangements for QFs.

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[8] Recall from ch. 4 that today's power systems employ a wide variety of generating technologies with diverse abilities to contribute to voltage and frequency regulation, to provide spinning reserves, and to schedule output and maintenance. Construction lead times and costs, and operating costs also vary widely. A vital role of coordinated planning and operation is to find ways to integrate the wide variety of available resources and harness their beneficial characteristics.

[9] See, for example, Power Technologies, Inc., *Application of Induction Generators in Power Systems* (Palo Alto, CA: Electric Power Research Institute, 1981), EPRI EL-2043. U.S. Congress, Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990s*, OTA-E-246 (Washington, DC: U.S. Government Printing Office, July 1985). Systems Control, Inc., *Integrating Dispersed Storage and Generation Into Power System Control* (Palo Alto, CA: Electric Power Research Institute, 1987), EPRI EL-4957.

[10] See, for example, OTA, op. cit., footnote 9.

Coordinating generation to follow changing loads and provide sufficient reserves at minimum cost already presents significant and challenging problems. An increasingly competitive supply market raises further challenges by reducing power system operators' direct control over coordinated operation and planning of generation and transmission. The following sections examine how the basic functions of following changing loads, maintaining reliability, and coordinating transactions would be effected.

Load Following

Frequency Regulation

Regulation—adjusting the power output of generators to follow moment-to-moment load fluctuations—is a fundamental function in reliable power system operation. Regulation is implemented using generator governors and automatic generation control (AGC)/economic dispatch to control the output of spinning reserves made available under unit commitment schedules.

How Much Control Is Needed?—There is no need for all generators to contribute to regulation.[11] The amount of regulating generation required depends on system conditions including anticipated load changes and the ramp rates and availability of other generators. Spinning reserves required for regulation are typically a few percent of load. Determining the amount of regulating capacity required is one function of unit commitment scheduling. Typically, regulating duty is shared by as many units as possible, each operating at slightly below its capacity. This allows the most rapid response, and minimizes the stress on any individual unit. So long as sufficient generation is controlled by governors and AGC, following changing loads presents few problems.

How Can Control Be Obtained in a Competitive Market?—There are both direct and indirect costs of contributing to frequency regulation. Participation in regulating duty slightly reduces a unit's fuel efficiency and tends to increase maintenance requirements and reduce lifetime, creating direct costs. Also, a generator participating in regulating duty operates at below its rated capacity some of the time, creating an indirect cost if payment is based on total energy output. Competitive suppliers are unlikely to bear the costs of contributing to regulation unless specific arrangements are made. Rather, they are likely to operate at a fixed power output not under AGC control.

As a result, regulation has to be explicitly included in operating arrangements under any scenario resulting in high levels of competitive supply penetration (scenario 1 and 2 at the utility's discretion; scenario 3 eventually; scenarios 4 and 5 immediately). Because most utility-owned generators typically contribute to regulation, calculating the precise value has not been an area of major concern or debate. More precise cost analyses may be required if a rationale for choosing either the amount of compensation or the preference in supply bidding is to reflect the cost of contributing regulation.

The direct costs of regulation—fuel efficiency losses and maintenance cost increases—are relatively small. For this reason, obtaining agreements giving an adequate amount for frequency regulation should not cause significant problems at any level of competitive supply penetration. Metering, communication, and accounting equipment may be required to allow the monitoring of generator performance according to agreement. Such equipment is typically not required now because of the unified utility ownership of generators.

Penetrations of nondispatchable technologies such as wind and photovoltaic generators are unlikely to be high enough to cause system-wide problems. To the extent that problems do arise, system planning may require the use of storage devices or in the extreme, limit total penetration.

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[11] In fact, nuclear generating units also do not typically contribute to regulation but operate at their full capacity all the time. Other supplies such as wind turbines, photovoltaics, and some cogeneration technologies are physically unable to provide regulation. Their power output depends on local conditions, not on the need to regulate frequency. Wind and solar generators, by having rapidly fluctuating output, may actually create a need for more regulating capacity.

Some QFs and IPPs contribute to frequency regulation now.[12] This gives some evidence of the willingness of independent suppliers to provide regulation when required to or compensated. In some cases, competitive supplies such as IPPs may operate essentially as traditional utility-owned generating units, as in the case of the Ocean States Power Project.

Cyclical Loads

Following daily, weekly, and seasonal cycles in load is also a fundamental function in power system operation. Unit commitment schedules are developed reflecting forecasted load changes over daily, weekly, and seasonal cycles. Generators in the unit commitment schedules increase or decrease their output either under AGC/economic dispatch following actual loads as required, or according to a schedule, following predicted loads. Performing economic dispatch and scheduling unit commitment for following load cycles is central to minimizing the operating costs of power systems.

How Much Coordination and Control Is Needed?—As with regulation, not all competitive supplies need to provide complete control of dispatch and scheduling to minimize operating cost. For example, current power systems use minimal dispatch and commitment scheduling of some plants since a large portion of demand, called the base-load, is constant. Nuclear units and to a lesser extent large fossil-fired steam turbines, with long and relatively expensive warm-up and cool-down requirements operate continuously to meet base-load requirements (although the fossil units may contribute to regulation as well). Few are designed to be operated in a cycling mode.[13] Furthermore, most modern large coal-fired generating units are not designed to operate below output levels of between 25 to 40 percent of maximum capacities.

The amount of base or off-peak load limits the use of generation which cannot be cycled. With a large amount of such generation operating during off-peak periods, low operating cost units may be turned off while less efficient cycling units are run. The result is true whether that generation is physically incapable of cycling or is only unschedulable due to operating agreements. Utilities typically choose a mix of generating units intended to operate as base load, intermediate, and peaking units reflecting daily and seasonal loads (see ch. 4).

The ability of generators to follow loads may also be limited by transmission availability, voltage constraints, and stability. Those constraints are highly dependent on the location and time-varying patterns of load and available transmission and generation. As a result of constraints on the ability of generators to cycle, additional voltage control devices may be required.

The possibility of reduced operating economics grows as the fraction of power which is not under coordinated and flexible scheduling and dispatch increases. The amount of schedulable generation required for following daily and weekly cycles depends on system conditions, including anticipated load changes and the ramp rates and availability of other generators and available transmission. Daily cycles vary from system to system but may have off-peak loads (typically between midnight and 6 a.m.) as low as 30 to 50 percent of daily peak loads.[14] Weekly and seasonal variations are even larger. Following such wide cycles requires a large amount of schedulable generation.

How Can Coordinated Control Be Obtained in a Competitive Market?—As with regulation, specific arrangements must be made for competitive suppliers to follow load cycles, since that requires operating at below capacity. Provisions for following cyclic loads have to be explicitly included in at least some operating arrangements under any scenario resulting in moderately high levels of competitive supply penetration (scenarios 1 and 2, depending on the utility's choice; scenario 3 eventually; scenarios 4 and 5 immediately).

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[12] In an OTA survey of 23 utilities, 6 of the 16 with nonutility generators on their system had at least some that contributed to regulation.

[13] A significant issue in life extension projects for old generators is that units designed for base load duty are expensive to retrofit for cycling duty.

[14] Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access, and Non-Utility Generation," contractor report prepared for the Office of Technology Assessment, Mar. 30, 1988, pp. 7-23.

To date, most nonutility suppliers schedule and dispatch their own operations.[15] For small amounts of competitive generation (possibly scenarios 1 and 2; and in early years, scenario 3), this approach should present few problems, particularly if purchase prices reflect less than optimal operating economics. Purchase prices for nonutility power may reflect time-of-day or seasonal variations in expected costs, encouraging supplier operation in peak hours and seasons over off-peak times. However, this approach will become increasingly less economic as the fraction of uncontrollable supply increases. The magnitude of increase in system operating costs depends on system-specific load and resource characteristics and the fraction of supply not under coordinated dispatch and scheduling. As a result, actual value of dispatchable v. nondispatchable generation is not entirely straightforward to calculate and may be the subject of disagreement in pricing or bid evaluation.

With large amounts of competitive or unbundled generation (scenarios 4 and 5 immediately; scenario 3 eventually; scenarios 1 and 2 possibly) explicit arrangements for coordinated dispatch and scheduling will be required. Such arrangements are becoming more common today. Increasingly, competitive suppliers and purchasing systems are developing operating agreements giving the system increased control over unit commitment scheduling and, in some cases, dispatch. In a few cases, independent suppliers are scheduled and dispatched by the utility, behaving much like a utility generator. In others, the amount of dispatchability is quite limited, say to a specific number of hours per year and only under specific conditions. For example, some QFs in California agree to reduce output for a specified number of hours per year when loads are low and inexpensive hydroelectric power would otherwise be wasted.

In these cases, the purchasing system can schedule unit commitment and dispatch the nonutility unit based on price and other contract terms. However, several factors determine the operating cost and efficiency of any plant, including whether it's operating at full or part load, the amount of reactive power output, and whether it's ramping. All of these factors may change over time for any plant. These details are important in determining the actual operating cost of a plant but may be difficult to include accurately in any dispatching agreement.

Spot pricing (or real-time pricing) is another approach which has been considered for coordinating the output of generators to follow loads. Under spot pricing, the price paid to competitive generators is recalculated regularly (e.g., hourly or daily) to reflect actual power system requirements and the availability of alternate supplies.[16] Based on these "real-time" prices, competitive suppliers schedule and dispatch their own generation reflecting system conditions.

The use of spot pricing requires new technologies, including algorithms for calculating prices and telecommunication equipment to transmit the prices. This approach holds some promise as an alternative to central dispatch for coordinating competitive supply markets. However, a lack of experience with spot pricing leaves significant uncertainties about its practical application. For example, such basic questions as the responsiveness of suppliers to hourly, daily, or weekly spot price changes are yet to be answered.

Coordinating Transactions

Coordination—scheduling and controlling the flows of power between utilities—is fundamental to interconnected power system operations. Scheduling transactions requires analyzing both the economic merit and physical ability to perform the transactions, as is the case in unit commitment and dispatch of a utility's own supplies. Inadvertent interchange, the unscheduled transfers of power between systems, is kept within NERC operating standards for Area Control Error by having sufficient generation available under AGC in each system to perform load following net of transfers. Thus the control of unit commitment scheduling and AGC for coordination is essentially an extension of that required for load following. Insufficient generation under AGC and unit commitment scheduling may result in poor regulation or increased inadvertent interchange.

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[15] According to an Edison Electric Institute survey of nonutility generation, less than 1 percent of interconnected capacity placed in operation since PURPA is fully dispatchable by the purchasing utility. Another 36 percent had limited dispatchability. In contrast, over 6 percent of pre-PURPA nonutility capacity was fully dispatchable, with another 14 partly dispatchable. *1986 Capacity and Generation of Non-Utility Sources of Energy*, Edison Electric Institute, 1988. Still, evidence of the willingness of most nonutility suppliers to provide dispatchability is limited. While most nonutility suppliers are not dispatchable, it is unclear whether that reflects a lack of emphasis placed on obtaining dispatchability in the past rather than an inability or unwillingness of the nonutility sources to be dispatchable.

[16] See, for example, F.C. Schweppe et al., *Spot Pricing of Electricity* (Boston, MA: Kluwer Academic, 1988).

Maintaining Reliability

Security

Maintaining security—preparing for continued operation after equipment failure or other disturbances and restoring service after outages—is essential to reliable power system operation. Security is maintained through unit commitment schedules that provide spinning and ready reserves and the coordination of scheduled outages of generation and transmission. Also, security constrained dispatch techniques may override economic dispatch to avoid transmission constraints and provide transmission reserves. Together with the coordinated engineering of relays and circuit breakers used to isolate failed or overloaded components, they ensure that no single failure will result in cascading outages.

How Much Control Is Needed?—NERC operating guides require each region or subregion to have spinning and ready reserves[17] equal to the loss of generation resulting from the most severe failure of a single generation unit or transmission line.[18] Typically, the required reserves are a few percent of total demand. These reserves are in addition to the spinning reserves scheduled for load following and must respond rapidly when needed. As long as competitive supplies are no larger than the largest existing generators and have similar reliability, higher levels of spinning reserves for security should not be required.

Beyond the need to schedule some units for spinning reserves, all generating units must be responsive to security constrained dispatch during emergencies and for restoration following a system failure. At a minimum, that response may be as simple as isolating the generator from the power system using automatic relays. Control of generation for security is relatively infrequent compared to the control required for load following. The occasions on which security constraints require overriding the least costly generation schedule are highly dependent on the location and time-varying patterns of load and available transmission and generation. When security constraints require redispatching generation, there are usually a number of choices of generators which could make the change. As a result, the frequency and amount of control actions required on any particular generator to avoid potential cascading outages are hard to predict, as is the total cost increase over optimal economic dispatch.

How Can Coordination Be Obtained in a Competitive Market?—From the perspective of a generating unit, coordinated control of scheduling and dispatch of spinning reserves for maintaining security and for frequency regulation are much the same. For this reason, the problems and approaches to obtaining spinning reserves are similar to those discussed above under load following.

Control of generation under security constrained dispatch is somewhat different for maintaining security than for following load, however. The main difference is that the control required for security is more immediate than for load following—if the proper control isn't exercised rapidly, bulk system failure may result. Also, the dispatch control required for security is less predictable and less frequent, and all generation must be under some control for occasional emergencies and system restoration following outages. Operating arrangements must specify the emergency conditions under which a normally undispatchable generator may be dispatched. Because of the difficulty of predicting and defining emergencies, developing and implementing appropriate arrangements will require careful attention.

Finally, planning secure operations requires resolving security-related system engineering problems involving both generators and transmission components. For example, stability problems may be due to the interaction of the system controls, the electro-mechanical behavior of generating units, and the properties of the transmission system. Possible solutions may require modifying generator voltage controls, adding controllable reactive power supplies on the transmission system, rejection of excess generation and load reduction by voltage control or intentional interruption of customers. System engineering problems depend on complex interactions between interconnected systems and their components and are hard to anticipate. In any power system, cooperation between all participants is required, and contract terms or other arrangements establishing the framework for solving the problems need to be established.

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[17] Ready reserves include generating units and interruptible loads available within 10 minutes.

[18] North American Electric Reliability Council, *NERC Operating Manual* (Princeton, NJ: December 1987), p. II.1.

Adequacy

Maintaining adequacy—providing enough supplies to meet consumer demand while remaining within the operating limits of system equipment—is also essential to reliable power system operation. In addition to unit commitment and economic dispatch discussed above, maintaining adequacy involves the vital function of adding new capacity. Coordinating maintenance scheduling is also important in maintaining adequacy. Maintenance schedules are designed to time equipment upgrades and repairs so that adequate supplies are always available while minimizing overall system operating costs. In the extreme, uncoordinated maintenance scheduling could result in insufficient available generation if for some reason enormous amounts of maintenance were planned simultaneously. The issues are similar to unit commitment scheduling for load following.

How Much Coordination of Planning Is Needed?— Long-term planning seeks to provide adequate resources to meet demand at lowest cost, reflecting the long construction lead times of generation and transmission. There has to be enough total capacity available after accounting for maintenance and unplanned outages to meet both real and reactive power requirements. Some capacity has to be capable of following changing loads to balance supply with demand. Transmission capability must reflect the location of both the supplies and demand. Furthermore, uncertainty abounds because demand is uncertain, as are fuel costs and the availability and performance of supplies.

An increasing reliance on competitive supplies alters traditional long-term planning in several ways. First, decisionmaking for new generation investment is increasingly separated from the power system planners. This reduces the system planners' direct role in developing supplies with desired characteristics such as the mix of base load and peaking units, fuel mix, load following ability, and siting near available or planned transmission. However, even in a competitive system, planners should still be able to direct the type of development desired.

Also, in the current power industry, utilities conduct cooperative planning studies to determine transfer capacities and requirements and perform coordinated regional studies. Data about system forecasts and resource plans are exchanged freely. An increasingly competitive supply environment may reduce the incentives and avenues for cooperative planning, with resulting increase in uncertainty and inability to plan optimally. The degree of reduced cooperation and the resulting reliability and economic impact are speculative and yet to be determined. Even if data is shared freely, the complexity of permutations of several competitors may make the planning problem of system optimization larger.

Second, a competitive supply market may increase uncertainty about the long-term availability and performance of supplies. For example, will a generating unit under construction be completed, or will a completed unit continue operation if the owner has severe financial problems?[19] How will the requirements of an industrial process affect the availability of an associated cogeneration unit? Will competitive suppliers without fixed prices contracts greatly increase price when supply shortfalls occur and reduce prices when there is surplus capacity? While these issues are not unknown in present utility planning, dissimilar objectives of competitive suppliers and the power system purchasing the electricity may increase volatility in the supply market.

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[19] Some part of any increased uncertainty over supplies may actually demonstrate a more responsive process in which proposers of uneconomic resources rapidly withdraw their projects when market conditions are unfavorable. However, it is conceivable that some competitive suppliers may have performance problems unrelated to a power system's need for their power. For example, a plant closing could halt operation of an industrial cogeneration facility regardless of the electric system's power requirements. Even in this case, the plant closing may not necessarily result in a loss of the power resource. If proper arrangements were made, the generator could conceivably continue operation, although not using the waste heat for industrial processes. Also, a plant shut-down would also eliminate the plant's electric load so the net effect on the power system would not be the simple loss of the generation unit.

Third, competitive markets hold some promise for shortening construction lead times. While lead time varies greatly by generation technology, there is a possibility that competitive generation markets will produce more efficient construction practices and thus shorter lead times for any technology.[20] As a result, the responsiveness of new supply to uncertain and changing power system needs may improve. To the extent that lead-time reductions occur, the importance of forecast uncertainty will diminish, to the benefit of system planning.

Coordinating Planning—Long-term contracts will be essential in coordinating planning. The process of developing contracts will be instrumental in communicating needs and defining the obligations of suppliers and the power system. By specifying prices and performance, including penalties for failure to perform, long-term contracts can help ensure that competitive supplies meet power system needs and mitigate uncertainty for both parties.

Individual competitive suppliers could also choose to develop generation without long-term agreements, speculating on future needs of the power system. This could occur either if no long-term contracts were offered, or if the supplier believed the future market would offer more favorable terms. However, there is no evidence that suppliers are willing to make such speculative investments. Similarly, a power system may find short-term agreements with speculative suppliers advantageous if a large enough oversupply develops or if it anticipates more favorable terms in the future.

Once a purchaser (a utility in scenarios 1, 3, and 4; a utility or a larger retail consumer in scenarios 2 and 5) has determined its supply requirements through its own planning process, it needs to select among alternate suppliers (assuming sufficient suppliers materialize). Supply requirements may be specified in terms as wide-ranging as the type of fuel used, location of units relative to existing and planned transmission, and type of operation (e.g., cycling or base load). In the past few years, utilities and regulatory agencies in several States have developed a wide variety of bidding procedures for procuring generation from competing suppliers.[21] The bidding procedures developed in different States incorporate a variety of mechanisms to accommodate the needs of coordinated planning and operations (see boxes 5-B, 5-C, and 5-D) which describe bidding in Virginia, California, and Maine.

In the face of uncertainty regarding how well new competitive procurement systems will work, one possible planning response is to increase generation and transmission reserves. The amount of additional generation reserves needed to maintain reliability, if any, depends on subjective assessments of not only the construction and operating performance of competitive suppliers relative to utility generation but also on the ability of new operating arrangements to adequately accommodate system requirements. Additional transmission reserves would support the higher level of generation reserves and also prepare for more varied siting decisions by competitive suppliers.

INCREASING TRANSMISSION ACCESS

Wheeling is the transmission of electricity from a seller to a purchaser using the transmission facilities of a third (or "wheeling") party. A key feature distinguishing wheeling from other electricity transmission is power ownership. Usually a utility owns the electric power flowing on its transmission system. The utility either generates the electricity or purchases it from others and then transports it for sale to customers. In wheeling, however, the wheeling utility neither purchases nor generates the electricity being transported; rather, it accepts power at one point and delivers it to another.

Wheeling allows both buyers and sellers of electricity access to expanded markets.[22] A variety of both purchasers and sellers may desire transmis-

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[20] Further, the choice of technologies may be shifted in favor of those with shorter lead times, although such a choice may occur without increased supply competition.

[21] M.J. Matousek and W.J. LeBlanc, "Bidding for Electric Resources: An Industry Review of Competitive Bid Design and Evaluation," prepared for Electric Power Research Institute, November 1988; M.H. Rothkopf et al., *Designing PURPA Power Purchase Auctions: Theory and Practice*, University of California, LBL 23906

[22] Wheeling normally involves the bulk power systems, but some small nonutility generators may be directly connected to the distribution system.

Box 5-B—Bidding in Virginia[1]

Status

In March 1988, Virginia Electric and Power Company (VA Power) solicited bids from qualifying facilities, independent power producers, and other utilities for 1,750 MW to provide power to come on-line starting between 1989 and 1994. VA Power chose about 2,000 MW for further negotiation from the nearly 14,000 MW of received bids. The accompanying figure breaks down the offers by fuel and generation type.[2] Final contracts are now being negotiated.

Approaches To Meeting Operating and Planning Needs

VA Power's system uses several approaches to ensure that its planning and operating needs are met. These include: minimum performance requirements and liquidated damages; a bid scoring system including various nonprice factors; and additional incentives for dispatchability.

Performance Requirements and Liquidated Damages—Liquidated damages are to be paid if a project does not come on-line and stay on-line as agreed. Performance requirements set limits on the number of days of forced outage and standards by which a bidder's compliance with dispatch orders are measured; capacity payments are to be cut if these performance requirements are not met. Some of the specific terms included are as follows:

- Each successful bidder must pay $30/kW in "earnest money." If a facility does not reach commercial operation within 2 months of the scheduled date, the bidder loses 10 percent of the earnest money in each of the next 10 months if the project does not come on-line.
- If a facility's dependable capacity proves to be less than expected during testing (before commercial operation), the bidder will pay a penalty of $30/kW of reduction.
- If, during the life of the power plant, dependable capacity is less than 90 percent of what was expected, the bidder will pay a penalty of $21.60/kW of reduction; this penalty is increased each year to keep pace with inflation.
- A penalty of 4 percent of the capacity payment each year is imposed for each day of forced outage beyond an established limit. The limit is the greater of 25 days or 10 percent of the days operated under dispatch. (This is an indirect encouragement to offer full dispatchability.)
- A penalty of 10 percent of the capacity payment each month is imposed for each time the facility does not operate within 5 percent of the dispatched level of operation; an alternative to this penalty is to declare the incident equivalent to a forced outage day.

Scoring System—The bid evaluation system accommodates VA Power's planning and operating needs by including a variety of nonprice factors. Explicit numerical values were not assigned to specific nonprice factors, although the general factors to be taken into account were listed and given a weight. The factors noted for bid evaluation and their relative weights were:

- 70 percent weight to price.
- 10 percent weight to project viability. This includes factors such as level of development and the experience and financial status of the bidder.
- 10 percent weight to fuel type. VA Power used this category to express its preference for fuels with stable prices (e.g., coal) and for projects that used instate fuels.
- 10 percent weight to other factors including location of the project in terms of its proximity to load centers and transmission lines, and extent of dispatchability.

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[1] The material in this box is drawn primarily from C.R. Roach, "Competitive Procurement of Generating Capacity: Summary of Procedures in Selected States," contractor report prepared for the Office of Technology Assessment, December 1988.

[2] *Electric Utility Week*, June 20, 1988, p. 19.

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Dispatchability Incentives and Requirements—Dispatchability received only slight encouragement from the bid evaluation: it is just one of six factors which, as a group, have 10 percent of the weight in evaluation. However, other incentives were given to bidders encouraging them to operate under full economic dispatch.[3] These incentives include the following:

- Dispatchable bidders were allowed to index their fuel prices to actual energy prices. Nondispatchable bidders were eligible only for a fixed (and thus riskier) price for a price tied to VA Power's ower cost units.
- As noted above, by offering dispatchability, a bidder limits the extent of performance penalties for forced outages. For example, a fully dispatchable plant would be allowed 36 days (10 percent of the year) of forced outages before a penalty is imposed, rather than the standard of 25 days.

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[3] In the *pro forma* contract, dispatchability is defined with the following requirements: 6-hour notice for start-up and shut-down, and 5-minute notice for changes in the level of operation. All facilities over 100 MW were required to be equipped for automatic generation control.

sion access. Without transmission access, an IPP or QF can only sell its power to the local utility that owns the transmission system. Similarly, a utility with competitive supplies cannot sell to the retail customers of neighboring utilities or to distant utilities unless access is provided through the intervening transmission system.

When power is wheeled to a utility for resale to its customers, the transaction is called "wholesale wheeling." Vertically integrated utilities may use both short- and long-term wheeling arrangements to displace their own existing or planned generation. Utilities with little or no generation of their own (in this report, called "requirements utilities"[23]) may use wheeled power to displace generation from the local generation and transmission utility. "Retail wheeling" is the delivery of power from a generator other than the local utility to an ultimate consumer such as a large commercial or industrial user.

To a large extent, the challenges in creating new methods of coordination revolve around developing workable definitions of obligations and rights of all parties and the institutions to carry them out. For example, when a retail or requirements utility chooses a distant supplier, does the local utility have an obligation to serve if those customers return? How much advance notice will purchasers and suppliers need to give the transporter? If the nonutility supplier fails to deliver power, does the wheeling utility have to provide back-up power? These definitions of rights and obligations, while critical for determining technical feasibility and economic impact, also raise fundamental questions of equity and appropriate levels of cooperation.

A wide variety of wheeling arrangements are possible, depending on the types of power suppliers, purchasers, and transporters and specific agreements among them (see boxes 5-E, 5-F, 5-G). Wheeling agreements must specify the amount of advance notice and other conditions under which the transporter can halt a transaction. The duration of wheeling arrangements may vary from hours to years. The amount of advance notice buyers and sellers must give the transporter before increasing or decreasing the amount of power to be wheeled may also vary.

The technical challenges and the likely cost and reliability impacts of increased wheeling depend on the buyers, sellers, and transporters and on the type of service being provided by each and their mutual obligations. The ability to accommodate increased wheeling also depends on the volume of transactions envisioned.

Increased wheeling poses new challenges for operation and planning. In today's power system operations, coordinated unit commitment and dispatch procedures perform several functions. They ensure that both real and reactive power needs are met and they provide sufficient ready or spinning reserves to following changing loads and prepare for

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[23] Requirements utilities with some of their own generation are called partial requirements utilities. Those with no generation of their own are called full requirements utilities.

Box 5-C—Bidding in California[1]

Status

The heart of California's bidding procedure is a long-term power purchase contract, referred to as the Final Standard Offer Number 4 (SO4).[2] SO4 requires a "price-only bid" competition through a "second price auction." Price-only competition means that the only variation among the bids is the price offered. Nonprice factors such as dispatchability and siting are not included. A second price auction means that all winning bidders are paid the same price, specifically, the price offered by the first losing bid.

Because there has been no need for additional generating capacity in the State recently, the bidding procedure has not been used yet. The agreed-to SO4 is the contract that will be used when generating capacity is needed and a bid solicitation is announced. However, the investor-owned utilities in the State are now mounting an effort to change the basic bidding regulations underlying SO4. The investor-owned utilities propose a change to the bidding system to include both price and nonprice factors. A switch to a first price auction has also been proposed.

Approach

The California bidding system has no numerical ranking which places explicit value on operational and planning needs. This does not mean, however, that these nonprice factors are not taken into consideration. California's system reflects nonprice factors through minimum requirements that must be met by all bidders and financial incentives for additional performance features. These requirements and incentives of the SO4 contract are discussed below.

Project Milestones

Each successful bidder must provide a $5/kW project fee to be refunded upon project completion. Project milestones are set which track the project development; from securing a site, through initial construction, to beginning operation. If a milestone is missed, the $5/kW project fee is forfeited and the utility may terminate the contract.

Liquidated Damages

Suppliers under firm capacity contracts are liable for liquidated damages if they default on the contract, or if they reduce the level of firm capacity. Liquidated damages are meant to compensate the utility for losses it incurs because the supplier does not deliver capacity and energy as contracted. If a supplier defaults on the contract or reduces the firm capacity rating, it must pay an amount equal to the utility's replacement cost for the energy and capacity.

Minimum Performance Requirements and Bonuses

For firm capacity contracts, the full payment is made on the facility's full capacity only if specific performance requirements are met. The primary requirement is that the facility achieve at least an 80 percent capacity factor during the on-peak times-of-day of each peak month. If the facility fails to meet this requirement, its firm capacity will be derated after a probationary period. Alternately, if the supplier substantially maintains a capacity factor of 85 percent or higher, the utility pays a bonus.

Curtailment Requirements and Incentives

Curtailment is a form of limited dispatchability. Under SO4, suppliers must agree to have their generation curtailed under certain circumstances. Suppliers are required to choose one of two forms of curtailment. Under the first, a supplier may be curtailed in cases of "Hydro Spill" or "Negative Avoided Costs." (Hydro Spill conditions occur when low system demand forces the utility to allow water to pass an unloaded turbine in order to reduce generation. Negative Avoided Costs are said to be incurred when the utility's high-cost units are at their lowest level of operation and the acceptance of further nonutility supplies would actually lead the utility to incur higher costs). If either Negative Avoided Cost or Hydro Spill conditions exists, the supplier must reduce generation to 30 percent of capacity or less. No energy payments are made during these curtailment periods.

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[1] The material in this box is drawn primarily from Boston Pacific Co., Inc., "Competitive Procurement of Generating Capacity: Summary of Procedures in Selected States," contractor report prepared for the Office of Technology Assessment, December 1988.

[2] The discussion herein is based on the SO4 contract negotiated by the utilities, private power producers, and commission staff as of June 1988.

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The second curtailment option allows the utility to curtail the supplier's generation up to 1,500 hours per year during off-peak and super-off-peak periods. No more than one curtailment can be imposed in a single day and the curtailment period cannot be less than 3 hours. Curtailments can be imposed during periods of Negative Avoided Cost. Economic curtailments can also be imposed; in these cases, energy payments are based (generally) on actual utility incremental costs. Supplier's choosing this second curtailment option receive higher energy prices in other off-peak and super-off-peak periods than those choosing the first option.

Adders, or Incentives for Other Performance

Additional payments by the utility can be negotiated to gain features such as greater dispatchability and for reactive power support. An early CPUC Decision ordered the utilities to consider the payment of "adders" if additional performance features are requested from suppliers beyond those in the SO4. The specific list of adders is as follows: emergency availability; black start capability; reactive power support; scheduled maintenance; real-time pricing; prescheduled dispatch; and full dispatchability. A later CPUC Decision created the possibility of "subtracters" as well. These payment adjustments would be based on a comparison of the performance features offered by the supplier through its contract to the performance features offered by the utility resource assumed to be avoided; adjustments may be upward or downward. Final details have yet to be worked out.

equipment outages. Finally, these functions minimize operating costs while remaining within the constraints imposed by the generation and transmission system capabilities.

By reducing the centrally coordinated control of generation, increased wheeling raises the possibility of less economic operation and reduced reliability. Reduced economics and operation problems are the same concerns that may result with improperly integrated competitive supplies discussed in the previous section. However, expanded transmission access adds new complications.

As the number and magnitude of wheeling transactions increase, scheduling use of the transmission will require increasingly accurate and objective analytical methods. In particular, calculating transmission capacity will be critical as was discussed above under long-term planning. The use of a local utility to provide load following capacity may also result in disagreements about the cost of providing spinning reserves, load following, and regulation services. More accurate methods of determining the cost of these services will then be required.

The following sections examine how wheeling may effect the functions of following load, coordinating transactions, and maintaining reliability.

Load Following

Frequency Regulation

Providing frequency regulation has a relatively small direct cost, assuming sufficient coordinated control has been obtained, and should not prove to be a very challenging requirement. Assuming the correct amount of regulating capacity has been acquired and brought under coordination of the local control area as discussed above, wheeling should add little complication. However, use of wheeled power will displace generation within the purchaser's control area. This may result in shutting down units during light load times, reducing the regulating capacity available.

Frequency regulation must be provided by the control area entity, whether that is an integrated utility (scenarios 1, 2, and 3), or the transmission company (in scenarios 4 and 5). Even with increased telemetry between individual sellers and buyers to keep each informed about the other's performance, the ability of an individual generator to exactly match load is limited since loads can typically change faster than an individual generator. Also, because fluctuations in individual loads tend to offset each other, the larger the power system being regulated, the smaller the fraction of regulating capacity required.

Box 5-D—Bidding in Maine[1]

Status

Established in 1984, Maine's bidding system is the oldest in the United States. Four Requests for Proposal (RFPs) had been issued by the end of 1987 and 78 contracts had been signed for a total of 500 MW. Operational projects total 275 MW, and another 222 MW were expected on-line by 1991. In its June 1987 solicitation, Central Maine Power's (CMP) solicited 100 MW and received 1,444 MW in actual bids. CMP's June 1987 solicitation is the basis for this discussion.

Approach

CMP's system has three main components. These components, prequalification (or screening); bid evaluation; and liquidated damages; are used to select new capacity to meet CMP's operating and planning needs.

Prequalification or Screening

CMP asked bidders to demonstrate their ability to construct and operate the proposed facility. The screening requires that a bidder present substantial evidence that the project is well along in areas such as engineering design and permitting, fuel contracting, and financing.

Scoring System

To accommodate CMP's planning and operating needs, the bid evaluation system considers a variety of price and nonprice factors. The value of the nonprice factors was explicitly quantified using six scoring indices. Each index had a base value of one, so all respondents started with a score of six.

- *Price Index:* This index reflected the extent to which the bidder's price was below CMP's forecasted avoided cost. For each percent discount offered by the QF, its score is increased by 0.1 points. For example, a 10 percent discount would add a full point to the score.
- *Capacity Index:* An additional point was added to the score for bidders providing reliable firm capacity. To obtain the point, the bidder must meet NEPOOL's test for firm capacity and (for thermal units) commit to high on-peak performance or (for hydro units) agree to a semi-annual capacity audit and to a minimum generation level.
- *Operating Index:* Dispatchability earned an additional 0.3 points. Coordinated maintenance scheduling earned 0.2 points more. Finally, scheduled operation favoring peak periods was rewarded by up to 1.5 points.
- *Security Index and Endurance Index:* These indices rewarded bidders that took steps to reduce the risk to CMP of future project nonperformance. Bidders that set up a security fund to cover the utility's cost of replacing the energy and capacity if the facility does not operate as contracted scored up to 0.5 points. Bidders that did not require levelized payments (i.e., payments exceeding the forecasted avoided cost in any year) or provided a security fund received up to 1.5 points.
- *On-line Index:* This index encouraged bidders to come on-line later in the 1990's. An additional score of 0.05 points is given for each year the Initial Delivery Date is set beyond 1990.

Liquidated Damages

Winning bidders are subject to penalties, or liquidated damages, if they do not perform as contracted. The payments for liquidated damages are an attempt to make the QF responsible for the cost of replacement energy and capacity if that QF falls short on providing capacity and energy as planned, or if the contract is terminated. A standard long-term contract specifies damages in cases such as capacity shortfalls during peak periods; energy deliveries below the guaranteed minimum; and abandonment of the contract.

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[1] The material in this box is drawn primarily from Boston Pacific Co., Inc., "Competitive Procurement of Generating Capacity: Summary of Procedures in Selected States," contractor report prepared for the Office of Technology Assessment, December 1988.

Cyclical Loads

The need to follow cyclical loads raises four issues for wheeling in addition to those described for competitive supplies. These are:

- feasibility for retail consumers and full requirements utilities,
- impact on the economy of operations,
- control center limits, and
- transmission scheduling.

Box 5-E—Southwest Bulk Power Market Experiment

In December 1983, FERC approved a 2-year experiment in bulk power marketing and transmission access involving six utilities in the Southwest.[1] The experiment was intended to determine the economic efficiency gains and competitive impacts of modifying FERC's regulation of coordination transactions—transactions between utilities with their own generating capacity. Transactions involving distribution utilities with little or no generation were not addressed. There were no apparent concerns or problems with the technical feasibility of implementing the experimental power transactions and transmission access.

In the experiment, the participants were allowed substantial freedom in setting prices for "economy energy" (for interruptible sales from hour to hour up to 30 days) and "block energy" (for sales extending at least one month). Prices were allowed to range from 0.9 ¢/kWh to 9.4 ¢/kWh. The utilities were allowed to retain 25 percent of the resulting savings as profit, with the remaining 75 percent flowed through to customers. (Traditional regulation requires 100 percent of such savings to be passed on to customers). Further, the utilities agreed to provide transmission access (up to technical limits) at a fixed price of 0.15¢/kWh, and thus not prevent trades involving other participants.

FERC contracted with the Rand Corp. for technical assistance in evaluating the experimental design proposed by the utilities; assessing the usefulness of the data; and analyzing the experimental results.[2] Rand published first year results in October 1985. The analysis of economic efficiency impacts was inconclusive: "Our findings with respect to efficiency are decidedly mixed, and vary depending on the analytic technique selected. . . . By some measures, efficiency increases under the experiment; by others it is unchanged or falls by a statistically significant amount."[3] Rand noted that the *first year* findings were possibly unrepresentative for several reasons.

According to Rand's first year report, the second year was expected to be more representative of the efficiency gains resulting from the experimental regulatory changes. Results of the experiment's second year have not been published to date.

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[1] *Southwest Experiment*, FERC Opinion No. 203, Docket No. ER84-155-000, Dec. 30, 1983. The six utilities were Arizona Public Service; the City of Farmington; El Paso Electric; Public Service Company of New Mexico; Salt River Project, and Southwestern Public Service (which began participation in the final 3 months of the first year.

[2] The Rand Corp. provided an advisory report to FERC before the experiment was approved. The Rand Corp., *Issues in the Design of a Market Experiment for Bulk Electrical Power*, December 1983.

[3] J. Acton and S. Besen, *Regulation, Efficiency, and Competition in the Exchange of Electricity: First Year Results From the FERC Bulk Power Market Experiment*, The Rand Corp., October 1985, p. vii.

Retail Consumers and Full-Requirements Utilities—Following the load cycles of retail customers and full-requirements utilities with wheeled power may prove difficult. For vertically integrated utilities (scenarios 1, 2, and 3), purchasing wheeled power presents no significant problem since they have the capability to follow their own loads. Similarly, control-area size transmission and distribution utilities (scenario 4) or distribution-only utilities (scenario 5) that buy power from individual generation companies with large amounts of supplies should have no problems beyond those described above under competitive supplies for generators within the control area.

However, for small full-requirements utilities and retail customers, following actual load cycles will require either: 1) the purchaser to accurately forecast loads far enough in advance to arrange a schedule with the supplier; or 2) the supplier to monitor the purchaser's loads and adjust output accordingly. Failure to meet one of these requirements will result in an over- or under-supply of wheeled power. This would have to be accounted for with the local control-area utility and may result in increased spinning reserves for frequency regulation. Accounting for transmission losses further impedes the ability to match supply with individual loads. The dependence of losses on ever changing system conditions and the possibility that some transactions may actually decrease losses add to the difficulty.

Impact on the Economy of Operations—With increased levels of wheeling in which individual

Box 5-F—Western Systems Power Pool: A Current Experiment in Transmission Access and Bulk Power Pricing

In March 1987, the Federal Energy Regulatory Commission (FERC) accepted another 2-year bulk power marketing experiment, called the Western Systems Power Pool (WSPP).[1] The WSPP experiment began on February 1, 1987. Like the Southwest Experiment, the WSPP experiment is intended to determine whether more flexible pricing and greater information sharing will promote more efficient use of generation and transmission facilities and reduce costs to consumers. As with the Southwest experiment, there have been no apparent concerns or problems with the technical feasibility of implementing any of the experimental power transactions, including transmission access.

There are several differences between the WSPP experiment and the Southwest Experiment. One principal difference is transmission access. The WSPP provides only for voluntary transmission service and gives substantial pricing freedom to the transmitting utilities. Transmission access prices are allowed to range from 0.1 ¢/kWh to 3.3 ¢/kWh. In contrast, the Southwest Experiment provided mandatory transmission access (subject to availability) at a fixed price of 1.5 ¢/kWh. Thus, according to FERC, the WSPP experiment will examine "whether mandatory transmission access is a prerequisite to a competitive market."[2]

WSPP also allows a much wider range of prices for generation than did the Southwest Experiment. In the WSPP experiment's first year, prices were allowed to range up to 24.5 ¢/kWh, compared to the earlier experiment's cap of 9.4 ¢/kWh.

Size is another difference between WSPP and the Southwest Experiment. WSPP is very large, including over 20 utilities in 10 Western States. The utilities in this region produce about 12 percent (82,000 MW) of the total electric generating capacity of the United States. That is substantially larger than the Southwest Experiment, which was open to six utilities in three States, with under 13,000 MW capacity. To implement the experiment over this large group of utilities, the WSPP experiment uses a computer "bulletin board" into which buy and sell offers are placed each day.

The experiment is scheduled to conclude on May 1, 1989, but the participants have requested a 2-year extension. As a condition of FERC approval, the participants are required to produce interim and final reports examining economic efficiency impacts and potential monopoly power. The interim report does not draw conclusions on these issues due to a lack of data.[3] However, the report notes that some transmission owners are holding less transmission in reserve for their own uses, resulting in increased availability to others.

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[1] Order Accepting Experimental Rates for Filing, FERC Docket No. ER87-97-001, Mar. 12, 1987.

[2] Ibid., p. 3.

[3] T.W. Keelin et al., *Western Systems Power Pool Assessment Interim Report* (Menlo Park, CA: Strategic Decisions Group, January 1989).

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purchasers and sellers specify generation patterns, the control area's options for economically scheduling and dispatching generation will be less flexible and less responsive than they are currently. A likely result is increased operating costs.

In particular, overall system economic impacts of scheduling constraints will be exacerbated if a large number of relatively small wheeling arrangements specify the dispatch and unit commitment of independent suppliers. For this reason, wheeling for retail customers (scenarios 2 and 5) and for smaller utilities, particularly those without generation (scenarios 2 through 5), are most likely to affect economic dispatch and scheduling. Wheeling of power to integrated utilities (scenarios 1, 2, and 3) or to large transmission and/or distribution companies (scenarios 4 and 5) should not have the same negative impact.

Control Center Constraints—A third complication for following cycling loads introduced by wheeling is a limit to the number of generators and wheeling transactions that can be handled from any control center. If the number of transactions increases significantly (most likely in scenarios 2 and 5; possible in scenarios 3 and 4), control center equipment, personnel, and procedures will have to

Box 5-G—Innovative Transmission Access: Turlock Irrigation District

In June 1988, FERC approved a novel agreement under which Turlock Irrigation District gained transmission access to a number of competing power suppliers.[1] [2] In exchange, Pacific Gas and Electric (PG&E) gained a pricing system allowing it to retain more of the savings from coordination transactions than were previously allowed. PG&E also gained release from responsibility to provide power and transmission beyond which it committed itself contractually.[3]

Turlock is a partial requirements utility, with capacity of approximately 157 MW and peak loads of approximately 266 MW in 1988. According to FERC, "Turlock has always been a captive customer of PG&E due to its reliance on the PG&E transmission system."[4] Under the new agreements, Turlock will have "reserved transmission service" providing 176 MW of import access to three other northern California utilities and to Southern California Edison at cost-based prices. Together with its own capacity and approximately 5.3 MW of firm capacity from PG&E, this gives Turlock sufficient resources to meet its own load. In addition, the agreement allows PG&E and Turlock to negotiate "coordination services." The coordination services would allow Turlock to pursue short-term purchases with PG&E and other utilities when low-cost opportunities exist. In addition, the agreement covers such provisions as charges for unauthorized power flows, voltage regulation, scheduling, and regulation services.

FERC's order of approval noted uncertainty and some concern about "whether PG&E may exercise any leverage over Turlock because of its control over Turlock's transmission access to other suppliers." The agreement is not an experiment, however, and no formal mechanism has been instituted to determine whether such leverage is exercised.

Finally, it's worth noting that neither FERC, nor PG&E, nor other intervenors expressed concern with the technical feasibility of reliably implementing the agreement.

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[1] *Pacific Gas and Electric*, FERC Docket No. ER88-219-000, Mar. 31, 1988.

[2] *Pacific Gas and Electric*, FERC Docket No. ER88-219-001, June 1, 1988.

[3] FERC approved a similar transmission access and pricing agreement between Modesto Irrigation District and PG&E in July 1988. *Pacific Gas and Electric*, FERC Docket No. ER88-302-001, July 5, 1988.

[4] *Pacific Gas and Electric*, op. cit., Mar. 31, 1988, p. 10.

be upgraded. The cost and reliability of control center upgrades to accommodate increasing numbers of transactions will be location specific. Increases in the volume of wheeling transactions, especially those whose levels change frequently, have already led to changes. For example, Houston Lighting and Power has added an energy scheduler to the dispatch staff, with over half his time dedicated to handling the effects of cogeneration and wheeling cogenerated power.[24]

Transmission Scheduling—Finally, increased wheeling creates an expanded challenge for transmission scheduling. In current power systems, following loads while controlling voltage and power flows on the transmission system to remain within physical limits is performed in part through generation control. With few exceptions, scheduling the use of transmission is not a significant problem today. If a utility has a transmission bottleneck, as many do, it selects an alternative (although less economic) generation dispatch which avoids the constraint. The options for different dispatch patterns are limited mainly by the operating capabilities of the generators. The ability to choose a variety of generation patterns is critical for reacting to the complex and uncertain changes in power flow requirements and transfer capabilities that power systems face.

As wheeling increases, scheduling transmission use independently of generation becomes increasingly necessary, distinct from the current combined generation and transmission scheduling problem. Generation scheduling constraints caused by wheeling arrangements will reduce ability to control transmission flows. In particular, if purchasers need wheeled power to follow changing and uncertain loads, the uncertain and changing pattern of generation usage could create unanticipated transmission loadings which would otherwise be avoided by redispatching generation.

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[24] Institute of Electrical and Electronic Engineers, Committee Report, "Problems in Coping With the Proliferation of Interchange Schedules," *IEEE Transactions on Power Systems*, vol. PWRS-2, No. 4, November 1987, pp. 883-889.

The more predictable the level of wheeling transactions, the less challenging transmission scheduling will be. For example, with long-term fixed patterns of power transfers, perhaps specified through contracts, the transmission scheduling problem reverts to a transmission planning problem in which new facilities can be developed as required (assuming capacity can be built as required and transmission owners can earn sufficient returns on investment).

Transmission scheduling involves setting priorities for who gets to use the transmission system and at what price. As wheeling transactions become more common, setting these priorities and prices will become increasingly contentious. These are issues of both economic efficiency and equity, and beyond the scope of this analysis.[25] There is no single technically correct solution to the priority and pricing problems, although a variety of approaches do exist. (See boxes on *Southwest Bulk Power Market Experiment; Western Systems Power Pool; and Turlock Irrigation District*). These demonstrate that untraditional uses of transmission are technically feasible and that arrangements can be developed that participants view as acceptable.

The idea of using marginal cost-based prices to allocate transmission capacity has received considerable attention. This method would have the effect of allocating transmission use to those willing to pay most for it. The marginal cost analyses are necessarily technical because of the complex physics and engineering of power systems.[26] Among the efforts, the United States Department of Energy and the New York State Energy Research and Development Authority have cosponsored development of public domain computer software for examining the marginal cost of wheeling.[27] The software, called WRATES, incorporates such factors as transmission losses, fuel costs, and the operational costs of generation and line capacity limits.

Coordinating Transactions

As noted above, increasing the number of transactions requires additional metering, telemetry, and telephone communication for the AGC. This is true for wheeling between control areas as well as within them. If the volume of transactions becomes large, power control centers of the transporting utility will need upgrading, and more dispatchers may be required.

Also, AGC systems used to coordinate transactions are based on the current structure of utilities in which control areas are clearly defined. Metering of tie lines into each area is an integral part of these systems and is easily accomplished. However, implementing large numbers of wheeling transactions may require revisiting the concept of control areas and AGC. In particular, the present concepts of control areas and AGC may be strained to the extent that wheeled power is used to continuously balance load and supply for a large number of retail customers or small full-requirements utilities. As loads and generators become independent from integrated utilities under retail wheeling or wheeling to requirements utilities, they can in concept become separate control areas purchasing and selling power using interchanges with the transmission system.

Maintaining Reliability

Security

With or without wheeling, maintaining system security depends on carefully coordinated control of generating units as described earlier. This control is needed both to schedule generation and transmission reserves and to redispatch generation and transmission following contingencies. Wheeling extends two issues beyond those previously described. These are:

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[25] See National Regulatory Research Institute (NRRI), *Some Economic Principles for Pricing Wheeled Power* (Columbus, OH: NRRI, August 1987).

[26] See, for example, ibid.; F.C. Schweppe et al., "Wheeling Rates: An Economic-Engineering Foundation," MIT Laboratory for Electromagnetic and Electronic Systems, Report TR 85-005, September 1985, and F.C. Schweppe et al., *Spot Pricing of Electricity*, op. cit., footnote 16. H.M. Merrill, "Economically Efficient Allocation of New York's Transmission and Distribution System," Power Technologies, Inc., June 1985.

[27] M.C. Caramanis et al., "WRATES: A Tool for Evaluating the Marginal Cost of Wheeling," IEEE 88 SM 649-6, IEEE/PCS 1988 Summer Meeting, July 24-29, 1988.

setting transaction priorities, and measuring transmission availability.

Setting Transaction Priorities—There is simply no way to maintain reliable operations unless wheeling is subject to availability of transmission capacity. The same is true of any use of transmission. Even if a wheeling transaction is scheduled, contingencies may occur that require curtailing the transaction. Any wheeling agreements, whether mandatory or voluntary, must recognize this reality (as is the case in all of OTA's scenarios). Thus purchasers of wheeled power must have either a back-up supply—either their own or purchased—or be willing to risk not meeting loads. (Note that curtailing a transaction does not equate with curtailing the load if back-up supplies have been arranged.)

As wheeling transactions become more common, determining which transmission uses to curtail or continue when transmission limits are reached, and determining the appropriate price of back-up supplies may become increasingly contentious. As with setting priorities and prices for transmission scheduling, these are issues of both economic efficiency and equity, and beyond the scope of this analysis. However, the technical requirements of operating a power system mandate that these issues be addressed.

Measuring Transmission Availability—Increasingly accurate measures and definitions of available transmission capacity will be required. Without accurate measures of capacity and costs, conflicts between those who want to wheel and transmission system managers will undoubtedly arise. Regulatory authorities may not have sufficient credible information on which to render decisions.

Recall from chapter 4 how available transmission capacity is measured today. There is no simple equivalent of the telephone company's busy signal on a power network. Transfer capacity is not the rating of a single line or a few lines. It is a function of the strength of the network as a whole. Transfer capacity depends on reliability criteria, which are selected somewhat subjectively. It varies as switching operations occur and as demand, generation, and transmission patterns change. Loop flows and actions taken by operators of other systems affect the available transfer capability. Furthermore, developing estimates of transfer capability requires a lot of engineering time and cooperation among all parties involved.

Transfer limits today are determined by complex system studies based upon reliability criteria established by mutual agreement among power system engineers. This is a satisfactory arrangement as long as the parties involved understand and trust each others' judgments. As the number of competing generating entities and wheeling transactions increases, there may be a greater need for more easily calculable and verifiable assessments of available transmission and transfer capability.

Adequacy

Long-term planning involves ensuring that adequate transmission and generation resources are available for operation. To the extent that wheeled power will be used for long-term supplies, expanded transmission access raises one crucial long-term planning issue in addition to those resulting from increased bulk supply competition. It is the prospect of increased planning uncertainty.

Increasing Planning Uncertainty—As increased wheeling allows power purchasers to buy from a greater number of suppliers, confusion regarding who will supply power to whom could exacerbate other capacity planning uncertainties. The result may be either under- or over-estimates of capacity needs for both generation and transmission.

Mandatory wheeling to retail customers (possibly in scenarios 2 and 5) raises the most critical source of uncertainty. Because of the long lead-times needed to build generation and transmission facilities, lack of sufficient advance knowledge of the plans of retail customers who may wish to obtain their power from outside sources could result in inadequate transmission facilities and excessive generation. Alternately, if a utility incorrectly assumes that a retail customer will obtain power through wheeling, excess transmission capacity and insufficient generation could result. For these reasons, advance notification of requests for wheeling and subjecting wheeling to transmission availability is required. A system of "transmission access on demand" or unrestricted access can not be implemented. (Note that none of the OTA scenarios include such unrestricted access.)

Wholesale wheeling and voluntary retail wheeling pose relatively few planning problems since there should be little confusion about who has obligations to acquire adequate power supplies. However, in every case, increased competition may reduce incentives for cooperative planning between utilities, generators, and customers, with a resulting increase in uncertainty and the inability to plan optimally.

As with competitive supplies alone, long-term contracts provide one instrument to communicate needs and define obligations of suppliers, buyers, and transmission systems. By specifying prices and performance, including penalties for failure to perform, long-term contracts can help ensure that competitive supplies meet power system needs and mitigate uncertainty for both parties. The allocation of risks and responsibilities between the power system and competitive suppliers under long-term contracts depends in part on performance and pricing terms.

CURRENT UTILITY PERFORMANCE

The cost (and the benefit) of implementing increasing competition depends largely on how the economy of current utility planning and operations are affected. This section briefly reviews current performance.

Individual Utilities

Most utilities appear to operate their plants efficiently, although that is difficult to ascertain. However, there is some indication that the quality of economic dispatch varies between utilities, although conclusions are difficult to draw. Consider a study performed by Philadelphia Electric Company for the Electric Power Research Institute.[28] That study found that different utilities had significantly different practices of monitoring the actual operating efficiency of their generators, resulting in slightly less than optimal economic dispatch.[29] If dispatchers believe that a suboptimal plant is operating at peak efficiency, they may call on it in preference to one that is actually more economic.

Units are maintained regularly to keep generation capacity operating efficiently, although there is a marked difference in the availability of otherwise similar plants owned by different utilities. Part of this difference is apparently due to differing maintenance programs.[30]

Utility planning and addition of new capacity has, in hindsight, often resulted in expensive and unneeded facilities. Still, the ability of independent power producers to outperform utilities in construction, maintenance, and operation of generators is yet to be determined, as is the impact of competition on planning uncertainty and planning practices.

Interutility Coordination and Power Pooling[31]

Interutility transactions are essential to minimizing operating costs of the U.S. power system. There appears to be a regular and increasing tendency on the part of systems with higher operating cost capacity to seek out more economic sources of power to purchase. The growth of imported power from Canadian sources to displace higher cost, oil fired generating capacity and to meet growing loads is a well known example, as are the increasing bulk transactions described in chapter 6.

However, there are some indications that economic interutility transactions, while high, could be substantially improved.[32] Proposed mergers between utilities indicate that some utilities believe that coordinated operations and planning could be improved. For example, SCEcorp (parent of Southern California Edison) in supporting its proposed merger with San Diego Gas & Electric noted that "Major cost savings are anticipated through more efficient use of generation and deferral or elimination of capital expenditures." In addition there would be staffing reductions. Projected savings from operations are $100 million annually and about $350 million in capital spending within the coming decade.[33] Similar projections of savings have accompanied other merger proposals such as that between Utah Power & Light and Pacific Power & Light.

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[28] Philadelphia Electric Co., *Improved Economic Dispatch of Power Systems* (Palo Alto, CA: Electric Power Research Institute June 1982), EPRI EL-2461, vol. 1.

[29] That study also identified opportunities for improved economic dispatch from more frequent monitoring. It is worth noting that the study was undertaken in the late 1970s, before significant competitive pressures were being felt, reflecting the industry's ongoing activities in identifying and developing areas for increased efficiency.

[30] See for example, U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty*, OTA-E-216 (Springfield, VA: National Technical Information Service, February 1984).

[31] The material in this section is drawn from Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access and Non-Utility Generation," OTA contractor report, March 1988, unless otherwise referenced.

[32] See, for example, E.J. Tirello, Jr. and M. Worms, *Electric Utilities: The Case for Consolidation*, Shearson Lehman Hutton Equity Research, March 1988. That study concluded that cost savings of $2.6 billion per year could be obtained through more efficient economic dispatch and maintenance procedures alone. See also, Federal Energy Regulatory Commission, *Power Pooling in the United States*, December 1981.

There are a number of regions where centrally dispatched power pools coordinate plans for system development and operate systems economically to reduce both long-run investment costs and short-run operating costs. These have taken the form of power pool agreements among unaffiliated utilities and the coordinated operation and planning of large utility holding companies. These existing operations offer one example of a practical and tested way of improving overall efficiency of the utility systems in other areas. One recent assessment of interutility coordination found that annual savings exceeded $15 billion—about three-quarters resulting from reduced capital investments with the remainder due to fuel cost savings.[34]

These economic gains are substantial. They could perhaps be augmented with an increased level of power brokering, pooling, and central dispatch systems. These approaches involve cooperation as well as competition. The benefits of pooling are balanced by responsibilities of pool members to deal openly and fairly with each other and to exchange data freely concerning future load projections, expansion plans, and operating costs. Centrally dispatched power pools require investment in a pool control center, communications and computer facilities, and the support of an adequate engineering and dispatching staff. These are not inconsequential costs. Ranges of initial costs for a large pool control center have been informally given at levels of $10 million to $50 million. A support staff of 30 to 40 professional level people might require an ongoing cost of $3 million to $5 million per year.

These costs must be compared to possible reductions in system expansion cost savings and annual operating cost savings that may be obtained from a central dispatch system for a large enough pool. Coordinating operations on a pool-wide basis rather than on an individual system basis means that the most efficient units within the region are being used to produce the energy required by customers on a planned minimum costs basis. The consumers' costs are reduced overall by this production efficiency. A system with a peak load of 10,000 MW and fossil-fired generation could have an annual fuel bill in excess of $1 billion per year. An operating cost savings of one-half per cent would be $5 million per year; enough to pay for the pool operating staff costs cited above.

A large portion of the savings from interutility coordination are due to the reduction in facilities required to handle the load growth in a region when the interconnected systems plan and implement system expansions on a coordinated basis. Installed reserve requirements for generation are reduced when systems substitute lower cost interconnection capability that allows them to share generation reserves for new generation capacity. This has been done in all of the power pools over the years.

The pool planning organization, whether a holding company staff or a committee organized from unaffiliated pool members, may plan for adequate reliability and lower generation reserves by taking advantage of the diversity in loads, the diversity in both planned and forced outages, and by coordinating capacity additions so new facilities are installed on a pool need basis rather than by each individual system. Transmission plans can be studied and implementations developed that will provide adequate transmission for exchanging power and energy on a regular and emergency basis.

Arrangements can be made to allow the use of the entire transmission system within the pool area for the mutual benefit of all of the pool members. In most pools, ties are "free flowing," eliminating the requirement for complex wheeling contracts. If transmission ownership is unbalanced, arrangements can be made to share transmission costs on a relatively simple basis. New transmission capacity may be planned jointly to develop optimal systems at the lowest costs.

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[33] *Electric Utility Week*, Aug. 1, 1988, pp. 7-8.

[34] J.A. Casazza, "Free Market Electricity: Potential Impacts on Utility Pooling and Coordination," *Public Utilities Fortnightly*, vol. 121, No. 4, Feb. 18, 1988, pp. 16-23.

The individual systems must relinquish something for these benefits. They must support the pool operation, both with sufficient funding and with adequate engineering support. The operating arrangements mean that the most efficient production units in the pool will be operated to supply customer demands throughout the power pool. The owners of these units must receive fair compensation and energy purchasers must be charged a fair price. The arrangements to accomplish this require negotiation and time to develop and implement.

Individual system members of a pool must agree to complete exchange of data and forecasts, which has been encouraged by the generally noncompetitive environment that utilities have been operating in to date. The members must be willing to coordinate plans and system developments. They must agree on generation plans and transmission system construction. They must be willing to surrender some of their responsibilities in operations and scheduling to the pool center. Finally they agree to coordinate plans to:

- avoid system emergencies,
- coordinate corrective actions during emergencies, and
- restore service after an emergency occurs.

It is logical to ask why there are not more power pools of affiliated and unaffiliated utilities. The answer is not clear. The potential savings in operating costs do require a fairly large pool size to support the annual costs of the pool operation. The individual utility may not escape the need for its own operations control center by belonging to a power pool of unaffiliated companies. (A holding company may be different with all of the generation operated by a centralized staff of the parent or one of its service company subsidiaries.) A substantial portion of the available operating savings may be achievable by other means such as economic interchange, power brokers, or long-term interchange agreements.

TECHNOLOGICAL ISSUES OF OTA's SCENARIOS

This section examines technological issues raised by increased competition as defined in OTA's scenarios. As discussed before, feasibility depends largely on developing new institutional relationships between suppliers, consumers, and transporters which accommodate the need for coordinated operations and planning of the power system. Implementing these new institutional relationships will likely require adding some new physical facilities and improving analytical capabilities.

In examining the ability to accommodate competitive supplies and transmission access, the question is not whether it can be done, but how much is feasible under what conditions without impairing reliability and economics. There is no point at which increased competition becomes clearly infeasible. Rather, increasing competition expands the institutional modifications required and raises the uncertainty of success.

Any proposed change from the existing system naturally raises uncertainty about how well the new system will work. We know that the power system of today does work, although some believe it to be somewhat inefficient or inequitable.[35] We also know that the system is currently evolving and accommodating increased competition: Nonutility generation and competition among suppliers is increasing substantially in many regions of the country; transmission access is also increasing, although to a lesser degree. The suppliers, transporters, and purchasers of power are defining institutional relationships and responsibilities which they feel meet their individual and joint needs. However, we will not know the actual impact of these changes on the reliability and economy of the power system for years to come.

The costs of implementing any scenario include developing new operating and planning procedures, adding new equipment and personnel to implement the procedures, and possibly less efficient economic dispatch, scheduling, and planning resulting from reduced coordination.

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[35] See chs. 1 through 3 of this report for a description of the concerns expressed over current industry performance.

Scenario 1: Reaffirming the Regulatory Compact

The first scenario envisions little change in industry structure. With no substantial, rapid increase in competition, existing operating and planning procedures will require only gradual evolution. This raises no major challenges or uncertainties.

Existing State regulatory programs would be modified to include ongoing approvals of major construction projects. Except for meeting the requirements of project preapproval or rolling prudence review, utility planning and operations would evolve along the lines they are following presently. It's possible that preapproval could result in increased development of power plants with long lead times and high capital costs. However, in an OTA survey of 23 utilities, only a few indicated they would consider revising their supply plans if given prior approval. Several utilities expressed concern over the risk of regulatory disallowances. However, many indicated they either accept that risk and build the generation most suited to their area's needs or believe that preapproval and rolling prudence would not be effective in reducing risk.

Supply Competition

Nonutility generation would continue to be developed under PURPA. Modifying the rules for pricing under PURPA would increase the likelihood that operating and planning requirements, or nonprice factors, would be reflected in avoided costs. These nonprice factors are receiving considerable attention today. Scenario 1 would encourage continued analysis of the requirements, costs, and benefits of different levels of coordinated utility control of dispatch and scheduling—both for load following and for maintaining security. The impacts of nonutility generation on planning would similarly receive continued analysis. For example, the requirements, costs, and benefits of such factors as fuel type and diversity, location relative to transmission facilities, and construction lead time and risk would receive continued attention. Utilities obtaining power from IPPs—also allowed under this scenario—would have to address these same issues of cost and value.

Transmission Access

Increased voluntary transmission access would be encouraged, too, although in an unspecified way. It is not known how effective these efforts will be to actually increase access. Efforts to encourage utilities to provide additional voluntary transmission access would likely involve continued analysis of the costs of transmission service. For example, for wheeling between vertically integrated utilities, analyses would examine reliability—the adequacy of and costs of transmission capacity; the costs of spinning reserves; the system engineering of relays and other protection devices—and the ability of control centers to coordinate an increasing number of transactions. For wheeling to small full requirements utilities, the costs and requirements of following changing loads—including frequency regulation and following daily, weekly, and seasonal cycles—require examination as well. Retail wheeling, although unlikely, would require similar analyses.

Scenario 2: Expanding Transmission Access and Supply Competition

Supply Competition

Under scenario 2, nonutility generation, including IPPs, would be further encouraged. The resulting change in costs and performance among competing supplies is speculative. As in scenario 1, to the extent that nonutility generation develops, nonprice factors will require increasingly careful analysis. Again, this will require site-specific analyses of the requirements, costs, and benefits of different levels of central control of generation (e.g., scheduling and dispatch for use in load following and maintaining reliability). The technical-economic questions that arise in system planning and operation will have to be made explicit and acceptably understood to all parties involved: utilities, regulators, nonutility generators, consumers, and other possible interveners. This may be challenging, since expertise in detailed areas of power system engineering and economic analyses are required.

Transmission Access

The second scenario also leaves the vertically integrated utilities in place. However, access to the transmission system is expanded by allowing utilities and large retail customers to seek mandatory wheeling. It is not possible to determine how much wheeling would result from implementation of a "broad public interest standard" for wheeling. The demand for transmission access will depend on the type of service mandated (e.g., load following or base load), the pricing of transmission service, availability of transmission capacity, and the availability of lower cost bulk power supplies from nonutility generators and remote utilities.

To the extent that transmission access is mandated, the efforts in analyzing costs and availability of transmission services and developing procedures for dispatch and scheduling for voluntary wheeling, as discussed under scenario 1, would be critical. The new wheeling orders would have to address issues of developing priorities for transmission scheduling and for curtailing transmission uses as contingencies occur. Provision of backup supplies and spinning reserves for reliability and adequate generation to follow changing loads must also be addressed for wheeling to retail consumers and requirements utilities.

Given the decreased authority of utilities to claim transmission limits and set priorities for use of constrained facilities (e.g., a rebuttable assumption that the capacity to wheel exists places the burden of proof on the utility), regulators must make provisions to ensure that significant degradation of reliability and economy does not occur under mandatory wheeling. Determining which wheeling orders can be issued without exceeding a system's capabilities will require expertise and data in detailed areas of utility engineering and analysis, including economic dispatch modeling, load flow analyses, and contingency and stability analyses. This expertise will also be required to give informed judgments on the prices charged under wheeling orders. Wheeling may require revising both generation and transmission system planning as new patterns of loads and suppliers develop. Provisions addressing the advance notification given by retail and requirements utilities before switching suppliers will need to be developed. Additional generation and transmission reserves may be required to account for any increased uncertainty or loss of coordinated control in operating and planning.

Scenario 3: Competition for New Bulk Power Supplies

Supply Competition

Scenario 3 creates a competitive market for all new electricity supplies. Utility affiliates would be able to "bid" to supply power in their own service areas, with appropriate safeguards. Utilities would remain the suppliers of last resort under traditional rate-base regulation. This would further encourage nonutility generation including IPPs. The resulting change in costs and performance among competing supplies is, again, uncertain. If competitive procedures prove more attractive than rate base supplies, scenario 3 will eventually result in a generation sector separate from transmission and distribution.

Utilities obtaining their new capacity through a competitive process will face the same challenges described under scenario 2. The technical requirements of analyzing the requirements, costs, and benefits of different levels of coordinated control of generation operation and planning, and developing procedures to obtain that control, remain. Many of these will need to be specified in advance of solicitations so that they can be reflected in pricing and evaluation. Again, included in the possible changes is a need to increase reserves of both generation and transmission as a response to greater uncertainty. The uncertainty involves not only how well generators will perform individually, but also how well new institutional relationships for coordinating individuals will work.

Regulators and utilities will have a new and challenging job in assessing the hard-to-quantify value of supply characteristics such as dispatchability, fuel diversity, location, and likelihood of project completion. As with mandatory wheeling, meeting this requirement will call for expertise in detailed areas of utility engineering and analysis, including economic dispatch modeling, load flow analyses, and contingency analyses, as well as system restoration, communications, and power control.

Transmission Access

Scenario 3 raises the same requirements and challenges of mandatory wheeling discussed under scenario 2. However, the extent of transmission access and who it is available to differs. Again, the extent to which transmission access orders would be requested is speculative. The provision for public interest transmission orders in scenario 2 would continue to be available to utilities. In addition, utilities seeking new power supplies or competing to supply others must offer transmission access to other suppliers. However, there would be no regulatory orders for retail wheeling, simplifying some of the wheeling issues discussed under scenario 2.

Scenario 4: Generation Segregated From Transmission and Distribution Services

Under scenario 4, the power industry would be restructured to create a competitive unregulated generating sector separate from transmission and distribution. That is, all supplies would be obtained by transmission and distribution companies from a competitive generation sector. Scenario 4 raises immediate problems of establishing coordinated operations. Coordinated control of generation for frequency regulation and following cyclic load changes, for maintaining reliability as system conditions change, and for controlling transactions between parties must be implemented. The transmission and distribution companies would retain the traditional utility responsibility of planning and acquiring supplies, although now from an unregulated competitive generating sector. The allocation of rights and responsibilities between generators and the transmission company must be carefully instituted.

The need to rapidly develop and implement radically new operating and planning procedures for competitive generation and mandatory wholesale customer transmission access makes scenario 4 considerably more risky and uncertain than the previous three. Both reliability and economy could be greatly reduced in the potentially long time required to experiment and develop new operating and planning procedures.

The vital technical difference between scenarios 3 and 4 is the abruptness and certainty of change in separating the generation sector. As existing utility-owned generating units are decommissioned, scenario 3 may eventually result in a transmission and distribution sector separated from generation similar to scenario 4. However, that outcome assumes that utilities will not successfully compete in building and operating generating units in their own service areas, which may not be the case. Thus, the evolution will occur slowly, if at all, giving a long time to develop the procedures required for coordinating operations and planning. Also, the long transition period gives many opportunities for experimentation and the chance to reverse the course of change if necessary.

Scenario 5: Common Carrier Transmission Service

The last scenario completes the separation of utilities into generation companies, transmission companies, and distribution companies. The transmission companies become common carriers with the responsibility to provide for adequate transmission capability. The main technical distinctions from scenario 4 are the separation of transmission from distribution; and the requirement to provide wheeling service to all retail customers, reintroducing the operating and planning issues discussed in scenario 2. As in scenario 4, a great technical challenge is presented by the abruptness and certainty of change. The need to rapidly develop and implement radically new operating and planning procedures immediately, including retail wheeling and the complete separation of transmission from distribution, makes scenario 5 even more risky and uncertain than scenario 4. Again, both reliability and economy could be greatly reduced in the potentially long time required to experiment and develop new operating and planning procedures.

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Regional Characteristics of the Electric Power Industry

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Chapter 6

Regional Characteristics of the Electric Power Industry

INTRODUCTION

The electric power industry in the United States is a diverse and complex patchwork of investor- and consumer-owned utilities, government agencies, cogenerators, self-generators, and independent power producers. Regional differences in industry composition, structure, and resource base characteristics are in large part attributable to patterns in population, climate, economic activities, and the history of electrification in each region. These variations can influence the outcome of any initiatives to expand transmission access and to inject more competitive pressures into the generation market. Differences in generation reserve margins, fuel mix, load growth, and coordination among regions will be important in encouraging or discouraging the participation of outside or nontraditional power generators in competitive markets.

This chapter begins with an overview of the structure and regional divisions of the electric power industry. Next, it provides an overview of regional differences, including, for example, demand growth rates, capacity margins, capital spending, electricity prices, and nonutility generation potential. Key regional issues and determinants for increasing competition in the electric utility industry and some of the anticipated regional impacts of implementing OTA's scenarios are also discussed. The chapter concludes with a detailed summary of the characteristics of the industry in each of the nine regional councils of the North American Electric Reliability Council, including, for example, generation and transmission capacity, fuel use, projected demand (load) growth, and reliability concerns.

NERC REGIONS

The electric power industry is subdivided by reliability council regions, by interconnections, by control areas and power pools, and by utility. This section will focus on the reliability council regions. Chapter 2 provides an overview of industry control areas, power pools, and interconnections.

The North-American Electric Reliability Council (NERC) and its regional councils were established in the late 1960s to assist utilities in providing for the reliability and adequacy of electric generation, transmission, and distribution systems. Formation of the organizations was aided by Federal legislation following the Northeast blackout of 1965. NERC is a major source of information about electric utilities' generation and transmission capacity and utilization.

Within the NERC federation there are nine regional reliability councils covering the Continental United States, Canada, and portions of Mexico as shown in figure 6-1. The Alaska Systems Coordinating Council is an affiliate member of NERC. Hawaii's utilities are not participants in NERC. See table 6-1 for council membership and subregions. Table 6-2 summarizes key operating and financial characteristics of NERC regions. The boundaries of NERC regions are established by the extent of the service territories of member utilities.[1] Operationally, six NERC regions are further divided into subregions shown in figure 6-2.

The regional councils coordinate planning and operations and exchange information on electricity supply, demand, and reliability. The councils provide NERC with annual and seasonal assessments of electricity supply and the factors affecting adequacy, reliability, and security.

Membership in NERC regional councils is voluntary and eligibility criteria are set by each region. Sometimes, membership (and benefits) is not available equally to all utilities within a region. Most of the regions limit full voting membership to utilities that own generation or transmission and that can have a *significant* impact on regional operations; there are often additional qualifications. For example, the Southwest Power Pool (SPP) requires a minimum generating capacity of 300 MW for full

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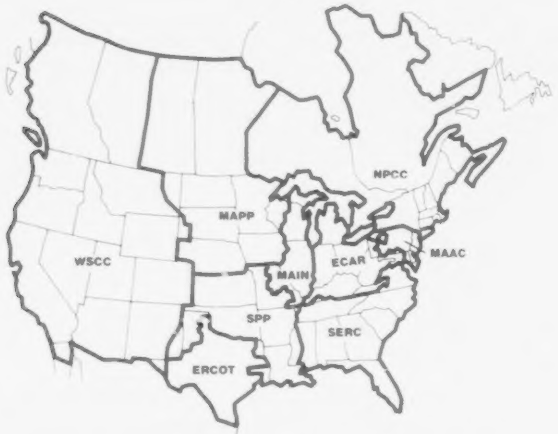
[1] Before 1987, regional boundaries and membership were determined by where the generating plants were located with the result that some utilities with widely dispersed operations, load centers, and generating plants could belong to several regions.

Figure 6-1—North American Electric Reliability Council



ECAR: East Central Area Reliability Coordination Agreement
ERCOT: Electric Reliability Council of Texas
MAAC: Mid-Atlantic Area Council
MAIN: Mid-American Interconnected Network
MAPP: Mid-Continent Area Power Pool
NPCC: Northeast Power Coordinating Council
SERC: Southeastern Electric Reliability Council
SPP: Southwest Power Pool
WSCC: Western Systems Coordinating Council

SOURCE: North American Electric Reliability Council, Copyright © 1988.

voting membership.[2] The Southeastern Electric Reliability Council (SERC) has a minimum generating size of 25 MW for voting members. Voting strength is often apportioned according to the relative loads of member systems with larger systems having proportionately greater influence over regional decisions than smaller systems. Participation in regional activities is usually available on a nonvoting basis to nonqualifying utilities either directly as associate members or indirectly through representation.

Two regions also function as power pools: the Mid-Atlantic Area Council (MAAC) and the Mid-Continent Area Power Pool (MAPP). Regional council/pool members agree to coordinate planning and operations, maintain adequate reserves, and provide certain transmission services for other members. For example, MAPP requires members to maintain a reserve margin of 15 percent. MAAC voting membership is coextensive with membership in the centrally dispatched Pennsylvania-New Jersey-Maryland Interconnection (PJM).

Over 95 percent of the generating capacity in the contiguous United States is owned by utilities associated with NERC—either as full voting members of reliability councils, as associate members of reliability councils, or as cooperating utilities. NERC's voluntary operating standards and guidelines thus have a substantial influence over system requirements and operating conditions and over determinations of transmission capacity availability.[3]

Regional councils are highly individualistic in establishing reliability and operating criteria and in collecting and dispersing information. Some regions require adherence to their own reliability and operating criteria and impose penalties for those who fall short of these obligations.[4]

INDUSTRY OWNERSHIP AND STRUCTURE

The electric power industry in the United States includes electric utilities, independent power producers, cogenerators, and self-generators. Within the utility sector there are some 200 investor-owned utilities; 2,000 publicly owned State, municipal, county, district, or joint action agency utilities; 900 consumer-owned cooperatives; 5 Federal power marketing agencies; and the Tennessee Valley Authority.[5]

Regional ownership statistics in table 6-3 reflect the very different market shares of private and public

---

[2] Information from the North American Electric Reliability Council 1987 Annual Report; and "Summary of Responses of the Regional Reliability Councils to the National Governors' Association Survey on Electric Transmission Coordination and Planning," OTA Contractor Report, Ohio Public Utilities Commission, Mar. 28, 1988 (hereafter "Reliability Council Survey Responses.")

[3] The role of utility or regional reliability standards in transmission capacity limits is discussed more extensively in chs. 4 and 5.

[4] See statements of individual regional membership qualifications in "Reliability Council Survey Responses," supra note 2.

[5] Complete and accurate information on the number of generators in the nontraditional or nonutility sector, their capacity, fuel use, and generation is not centrally available through the Energy Information Administration or industry sources.

Table 6-1—U.S. Membership of North American Electric Reliability Council Regions

NERC region	States	Member systems	Area served (square miles)	Population served
ECAR—East Central Area Reliability Coordination Agreement	MI,OH,WV,IN Most of KY and parts of VA,MD,PA	18 members 16 IOUs 2 Cooperatives	194,000	36 million
ERCOT—Electric Reliability Council of Texas	Most of TX	76 Members 6 IOUs 49 Cooperatives 20 Municipals 1 State agency	195,000	11 million
MAAC—Mid-Atlantic Area Council	DE,NJ,PA,DC, and parts of MD & VA	11 Members (all IOUs) 5 associates (representing group of cooperatives)	48,700	21.1 million
MAIN—Mid-American Interconnected Network	IL, and parts of MO,MI, and WI	13 Members 11 IOUs 1 Cooperative 1 Municipal 1 Associate	170,000	18 million
MAPP—Mid-Continent Area Power Pool	IA,MN,NB,ND, and parts of WI,SD,MT,MI,IL	27 Participants 11 IOUs 8 G&T Cooperatives 4 Municipals 3 Public power districts 1 Federal agency 16 Associates	420,000 (U.S.)	13.6 million
NPCC—Northeast Power Coordinating Council	CT,ME,MA,NH,NY,RI,VT	18 Full members 17 IOUs 1 State authority	112,527	27.4 million
SERC—Southeastern Electric Reliability Council	AL,FL,GA,NC,SC,TN, and parts of VA,MS, and KY	28 Member systems 16 IOUs 8 Municipals/public 2 Cooperatives 2 Federal agencies 8 Associates	345,650	25 million
SPP—Southwest Power Pool	AR,OK,KS,LA, and parts of MS,MO,TX, and NM	41 Systems 17 IOUs 12 Municipals 8 Cooperatives 4 Government agencies	500,000	25+ million
WSCC—Western Systems Coordinating Council	AZ,CA,CO,ID,NV,OR,UT, WA,WY, and parts of NM,MT,SD,TX	57 Members 19 IOUs 17 Municipals 16 Public power (includes 6 cooperatives) 5 Government agencies 4 Associates	1.8 million (US & CAN)	48 million

SOURCE: NERC *1986 Annual Report*, and the *1988 Reliability Assessment: The Future of the Bulk Electric System in North America 1988-1997*, September 1988.

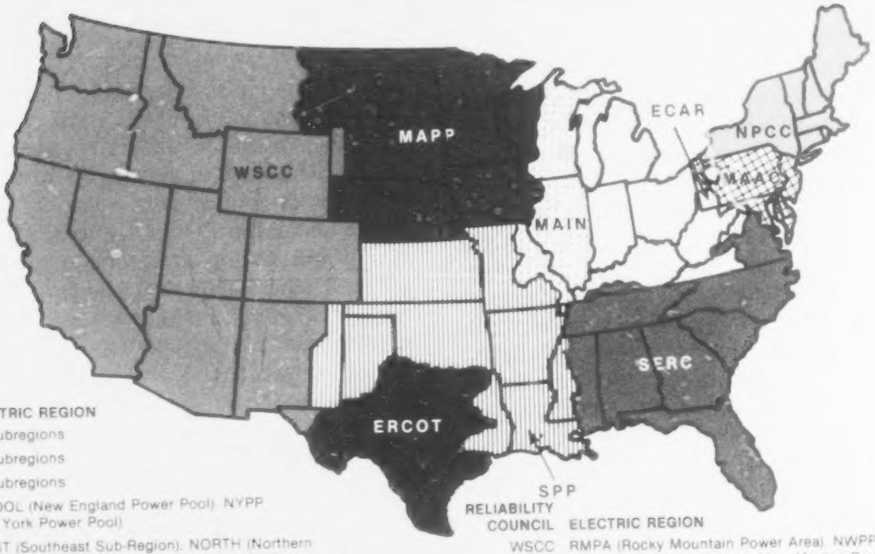
power suppliers. Private or investor-owned utilities operate in all States, except Nebraska. They dominate power generation, transmission, and wholesale and retail sales in all but one region (East South Central). In Hawaii, all power is supplied by private utilities. In the South and West, public power, cooperatives, and Federal power agencies account for a larger portion of sales to retail customers than elsewhere in the Nation, reflecting the historical role of these entities in the electrification of these

Table 6-2—Characteristics of Electric Utilities by NERC Region

Region	Projected 1988 installed capacity (MW)	Projected 1988 capacity margin (percent summer) (percent winter)	1988-97 avg. growth (percent summer) (percent winter)	1988-97 avg. annual NEL growth (percent)	Dominant fuels (percent)	Projected 1988 net imports (million kWh)	1988 Capital spending (billion of dollars)	Transmission network-1987 (circuit miles)
ECAR	97,380	23.0 27.0	1.6 1.7	1.5	Coal (90)	-19,950	3.3	15,764
ERCOT	49,880	21.3 37.1	2.4 3.2	2.9	Gas/oil (46) Coal (40)	1,158	1.7	6,871
MAAC	48,582	19.0 34.3	1.3 2.0	1.8	Coal (53) Nucl (31)	24,587	3.2	6,552
MAIN	49,607	25.4 40.9	1.5 1.9	1.7	Coal (54) Nucl (44)	1,621	1.9	5,397
MAPP	30,619	28.4 37.9	1.5 1.6	1.7	Coal (67) Nucl (67)	-8,057	1.0	13,827
NPCC	53,714	22.1 26.5	1.9 1.6	1.8	Nucl (28) Gas/oil (37) Coal (19) Hydro (14)	26,605	1.9	6,046
SERC	139,334	20.0 23.8	2.4 2.4	2.4	Coal (60) Nuci (27)	-9,218	7.2	26,899
SPP	65,621	26.7 45.5	1.9 2.2	1.9	Coal (54) Gas (26) Nucl (16)	-442	1.5	10,685
WSCC	123,022	31.5 36.7	1.9 1.7	1.8	Coal (35) Hydro (33) Nucl (14)	38,248	5.9	52,345
TOTAL	657,759	24.3 32.8	1.9 2.0	2.1		72,988	27.5	144,386

SOURCE: Office of Technology Assessment, from various NERC publications.

Figure 6-2—Electric Regions in the Contiguous United States



RELIABILITY COUNCIL	ELECTRIC REGION
ERCOT	No Subregions
MAAC	No Subregions
MAPP	No Subregions
NPCC	NEPOOL (New England Power Pool), NYPP (New York Power Pool)
SPP	SOEST (Southeast Sub-Region), NORTH (Northern Sub-Region), WCENT (West Central Sub-Region)
MAIN	CECO (Commonwealth Edison Company), SCIM (South Central Illinois-East Missouri Group), WIUM (Wisconsin-Upper Michigan Systems Group)
SERC	FCG (Florida Electric Power Coordinating Group), SOCO (Southern Company Group), TVA (Tennessee Valley Authority), VACAR (Virginia-Carolinas Group)

RELIABILITY COUNCIL	ELECTRIC REGION
WSCC	RMPA (Rocky Mountain Power Area), NWPP (Northwest Power Pool Area), AZNM (Arizona-New Mexico Power Area), CASN (California-Southern Nevada Power Area)
ECAR	APS (Allegheny Power System), WOIM (West Virginia-Ohio-Indiana-Michigan Systems), WPANCO (Western Pennsylvania-North Central Ohio Group), CDH (Cincinnati-Dayton-Hamilton Group), KY (Kentucky Group), IND Indiana Group), LMS (Lower Michigan Systems)

SOURCE: Office of Technology Assessment, 1989.

regions. (These numbers can be somewhat misleading, however, because many public power utilities purchase wholesale power generated by private companies.)

Among investor-owned utilities, the large holding company power systems are important regional entities which control access to major regional transmission facilities. Their size, strategic locations, and financial resources would make them formidable competitors in large regional markets under any competitive industry structure. Regulated holding companies are important regional influences in the Northeast Power Coordinating Council (NPCC), MAAC, East Central Area Reliability Coordination Agreement (ECAR), SERC, and SPP.

REGIONAL DIFFERENCES

The electric power industry displays regional variations in demand growth rates, generating capacity, capacity margins, fuel use, levels of reliability, and capital spending, as well as the potential for nonutility generation. Some of these differences are summarized in table 6-2.

Electricity Demand Growth Rates

NERC indicates that U.S. demand for electricity or net energy for load (NEL) will grow at an average annual rate of 2.0 percent between 1988 and 1997.[6]

Nationally, this is a downward revision of overall demand projections from those published by NERC

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[6] North American Electric Reliability Council, *1988 Electricity Supply and Demand for 1988-1997*, October 1988, p. 18. Electricity demand is measured as net energy for load—defined by NERC as the annual electric energy needed to serve the utilities' customers. NEL includes transmission losses and represents the electrical energy generated by the utilities' own generating sources plus electrical energy purchases from other utilities and from nonutility generation facilities, less electrical energy sales to other utilities. NEL does not include energy pumping requirements for pumped storage generating facilities. NEL is roughly equivalent to DOE's Net Generation.

Table 6-3—Capacity, Generation, and Sales by Class of Ownership and Region, 1987 (percent by region)

NERC[a] region Class of ownership	Number of utilities	Installed capacity (percent)	Net generation (percent)	Sales to ultimate consumers (percent)
ECAR:				
Private	50	88.1	90.9	88.7
Public/State	230	7.6	3.0	5.7
Cooperative	113	4.4	6.1	5.6
Federal	—	—	—	—
ERCOT:				
Private	7	40.5	81.0	80.8
Public/State	57	57.4	15.9	12.4
Cooperative	65	2.1	3.0	6.8
Federal	—	—	—	—
MAAC:				
Private	19	96.5	98.3	95.1
Public/State	58	3.5	0.4	1.8
Cooperative	22	*	1.3	3.1
Federal	—	0	0	—
MAIN:				
Private	22	96.9	97.5	91.5
Public/State	149	2.4	1.5	5.5
Cooperative	51	0.7	0.9	3.1
Federal	1	0	0.1	0
MAPP (U.S.):				
Private	18	51.5	48.4	59
Public/State	497	28.9	25.3	26.3
Cooperative	189	19.5	26.3	14.7
Federal	—	—	—	—
NPCC (U.S.):				
Private	62	85.4	81.7	88.8
Public/State	134	14.6	18.2	10.7
Cooperative	16	*	*	0.5
Federal	—	0	0	0
SERC:				
Private	22	69.9	68.1	64.6
Public/State	312	8.3	7.7	20.4
Cooperative	187	1.6	6.1	11.8
Federal	2	20.2	13.1	3.2
SPP:				
Private	20	79.9	77.1	77.9
Public/State	293	11.4	7.1	9.5
Cooperative	158	8.7	13.2	12.6
Federal	1	0	2.6	0
WSCC (U.S.):				
Private	32	55.5	51.9	64.3
Public/State	240	41.7	20.9	24.8
Cooperative	139	2.8	3.5	4.3
Federal	6	0	23.7	6.6
NERC[b] (U.S.):				
Private	252	73.5	75.2	77.0
Public/State	1,970	18.6	10.5	14.2
Cooperative	940	3.6	5.8	6.9
Federal	10	4.3	8.5	1.9

[a] North American Electric Reliability Council.

[b] Excludes Alaska and Hawaii.

*The absolute value of the number is less than 0.5.

NOTES: Totals may not equal sum of components because of independent rounding. Data shown, except for installed capacity, are preliminary data reported on the Energy Information Administration Form EIA-861. The EIA-861 data were used since net generation and sales data are both reported on that form. The data for net generation and sales to ultimate consumers may not agree with numbers published in EIA reports, which are based on the Form EIA-759, "Monthly Power Plant Report," and the Form EIA-826, "Electric Utility Company Monthly Statement."

SOURCE: Energy Information Administration, Form EIA-860, "Annual Electric Utility Report, Preliminary Data."

in 1987 and continues a recent trend.[7] All NERC regions except NPCC (U.S. portion) and MAAC projected lower 10-year NEL growth in 1988 than they did in 1987. Projected regional NEL growth rates for 1988-1997 vary considerably. (See table 6-2.) They range from a high of 2.9 percent in the Electric Reliability Council of Texas (ERCOT) region to a low of 1.5 percent in the ECAR region. Variations are evident within regions as well. For example, the Western Systems Coordinating Council (WSCC) region projects a growth rate of 1.1 percent for the Northwest Power Pool Area, but a 3.4 percent growth rate for the Arizona-New Mexico Power Pool Area for the same period. What causes these fluctuations in growth rates among regions? Population growth, climate, industrial activity, regional nonutility generation capacity, and cost are just a few of the factors that influence demand growth.

Peak demand for electricity in the United States is highest in the summer. NERC projects that U.S. summer peak load will likely grow at an annual rate of 1.9 percent between 1988-1997; projected regional summer peak growth rates range from 1.3 percent in MAAC to 2.4 percent in ERCOT and SERC (see table 6-2). Winter peak demand has been growing faster than summer peak in six of the nine NERC regions; these are ECAR, MAAC, MAPP, Mid-American Interconnected Network (MAIN), ERCOT, and SPP. All six regions are expected to remain summer peaking up to 1997.

Generating Capacity

The amount, type, and age of installed generating capacity also varies by region, as does the pace of planned additions (see figure 6-3 and table 6-4). These differences reflect varying load characteristics (population, climate, economic activity) and resource availability.

According to NERC, most regions currently have more than enough capacity to meet their increasing needs under most circumstances for several years at least. This assessment rests on two critical assumptions: that electricity consumption increases at the projected growth rates; and that existing and planned generating capacity is available when needed.

This assessment of adequacy includes built-in safety factors in both a 15 to 20 percent minimum reserve capacity and other capacity that is uncounted to allow for scheduled maintenance and could be used if needed. Even so, if actual demand growth exceeds the assumption or if existing and planned generating capacity levels are not reached, several regions and systems could see increased reliability risk or experience actual shortfalls in electricity supplies. Among the analysts that have examined these prospects, there is some disagreement about when and where additional generation capacity may be needed.[8] The disagreements are rooted in differing expectations over future growth in electricity demand and whether or not planned capacity is built as scheduled.

Generation and Fuel Use

More than half of the electricity generated in the United States in 1987 (about 2.6 million gigawatt hours (GWh)) came from three regions: SERC, WSCC, and ECAR. Figure 6-4 shows electricity generation by fuel and region.

About 55 percent of the electricity generated in 1987 came from coal-fired plants. Six regions used coal for more than 50 percent of their electricity generation—ECAR, MAAC, MAIN, MAPP, SERC, and SPP. Two regions, MAIN and MAAC, generated a significant percentage of their power from nuclear plants. Hydropower is an important generating source in the U.S. portion of WSCC, accounting for about one-third of the electric energy production in that region in 1987, an unusually dry year. Hydroelectric plants also contributed 15 percent of generation in NPCC in the United States.

In some regions, the oil and gas capacity base is quite high. NERC projects that oil and gas will provide about 65 percent of capacity in ERCOT, over 50 percent in NPCC (U.S. portion), and 45.5 percent in SPP. Oil and gas plants are generally used for peaking power, but in some regions they also

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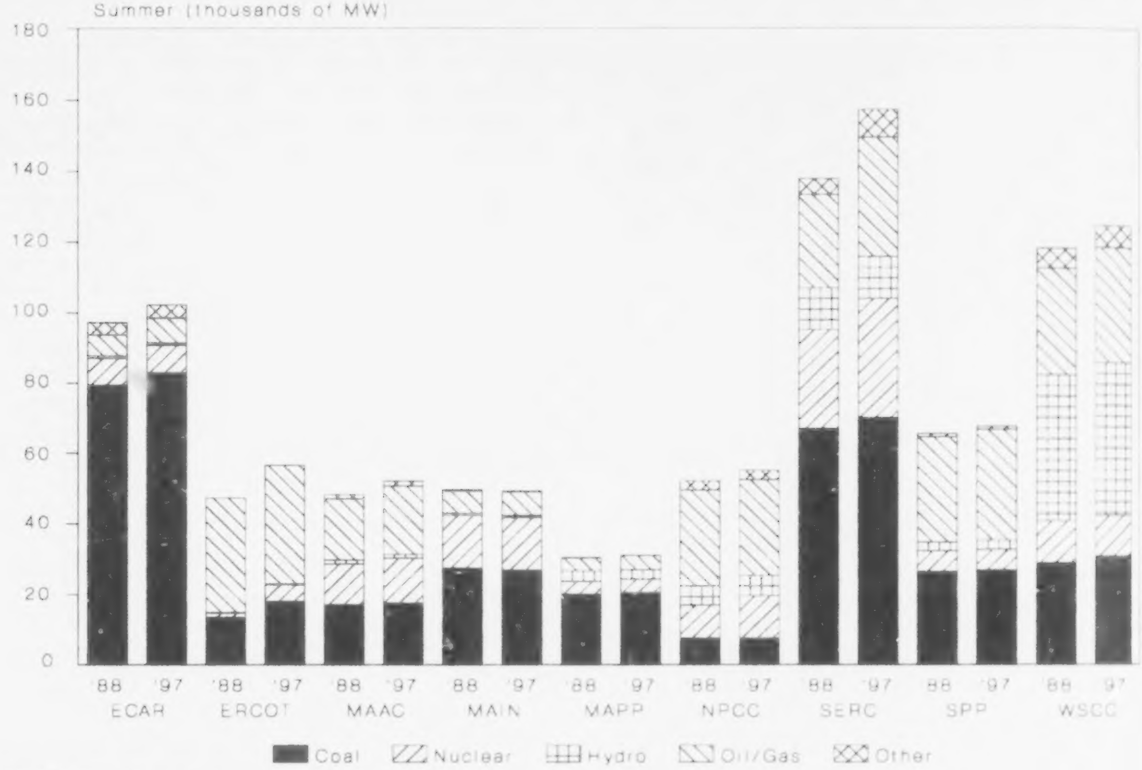
[7] Ibid. These 10-year demand forecasts, are of course highly uncertain. To account for this uncertainty, NERC also estimated that the actual annual NEL growth would fall within a range of 0.9 percent per year to 3.5 percent per year. NERC did not provide comparable ranges for regional forecasts.

[8] See for example, U.S. Department of Energy, Deputy Assistant Secretary for Energy Emergencies, "Staff Report: Electric Power Supply and Demand for the Contiguous United States 1987-1996," DOE/IE-0011, February 1988; Amy Abel, "Canadian Electricity, the U.S. Market and the Free Trade Agreement," Congressional Research Service Report 88-427 ENR, July 5, 1988.

Figure 6-3--Installed Generating Capacity, 1988 and 1997



SOURCE: Office of Technology Assessment from NERC data.

contribute significantly to meeting base-load needs. For example, ERCOT generated 46 percent of its electricity from oil and gas in 1987, and NPCC-U.S. produced almost 39 percent of its electricity from oil and gas.

Capacity Margins

Regional and individual utility variations in capacity margins reflect differences in system characteristics, such as the duration of the peak load season and the outage rates for different ages, sizes, and types of generation capacity. Also, differences in the availability of supplementary bulk power from other systems will affect capacity margins. See table 6-5 showing projected capacity margins from NERC by region for 1988-1997 and figure 6-5 showing projected reserve margins at the time of regional peak demand.

Determination of adequate capacity margins varies from region to region with a margin of 15 to 20 percent generally considered desirable. See discussion in chapter 4. NERC expects capacity resources in all regions to be adequate to meet projected demand in 1988-97; however, overall capacity margins will decrease over the same period.

One of the results of the lower capacity margins could be that some utilities may have less flexibility in dealing with more severe situations. Another result could be the increased likelihood of load curtailments if a shortage develops.

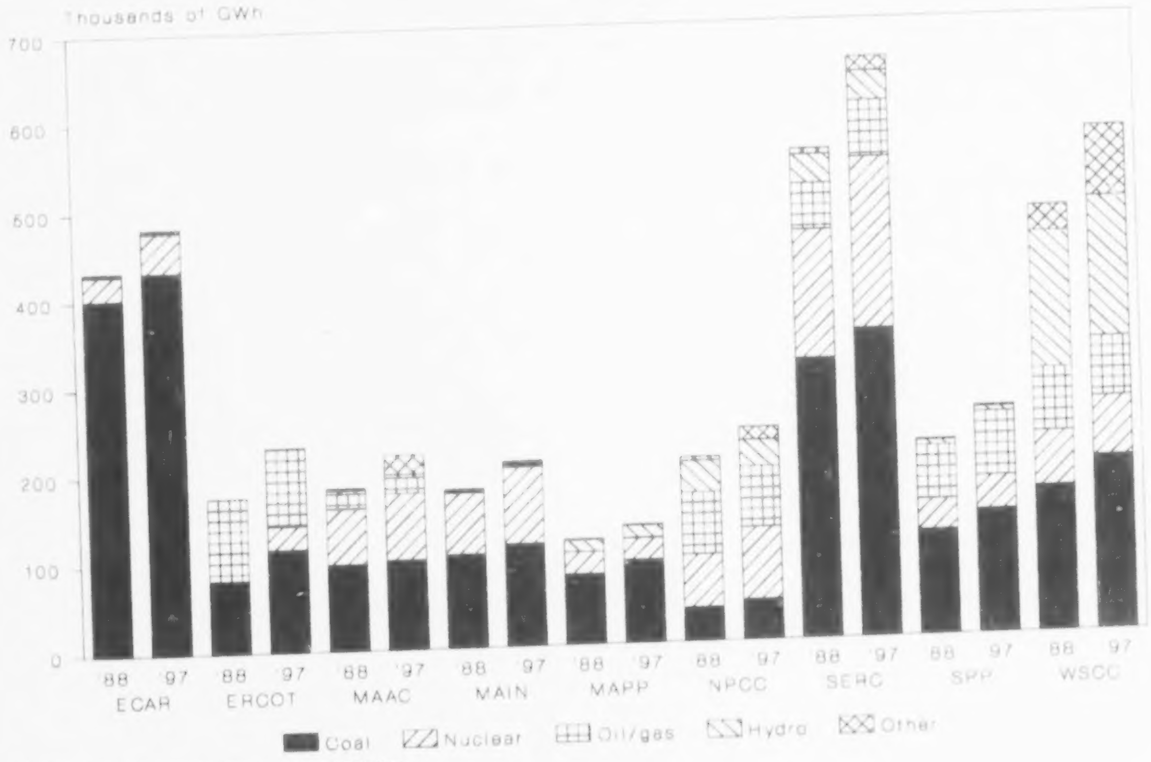
Still another result could be greater reliance on older generating units. This in turn will increase

Table 6-4—Life Extension Resource Base: Age of Fossil-Fired Steam Plants in 1995 by Region

	Fossil-fired capacity ≥ 30 years old in 1995		
Region	MW	As a percent of fossil-fired capacity	As a percent of all installed capacity
ECAR	33,335	32.9	31.9
ERCOT	12,186	20.4	22.0
MAAC	11,589	35.5	22.0
MAIN	14,172	41.3	28.0
MAPP (U.S.)	6,695	25.8	22.5
NPCC (U.S.)	16,806	52.6	30.0
SERC	32,239	35.8	20.9
SPP	21,359	30.0	32.0
WSCC	24,811	39.5	18.5

SOURCE: Office of Technology Assessment, from data generated by E.H. Pechan & Associates, December 1984, and North American Electric Reliability Council, *1987 Electricity Supply and Demand for 1987-1996*, November 1987.

Figure 6-4—Projected Electrical Energy Production by Fuel, 1988 and 1997



SOURCE: Office of Technology Assessment from NERC data.

maintenance requirements and result in more outage time, as well as an increase in sulfur oxide emissions. A number of developments could easily change supply adequacy or excess capacity into a shortage situation. These include delayed capacity additions, nuclear safety concerns which result in

Table 6-5—Estimated Regional Capacity Margins (percent of planned capacity resources)

Regions (U.S.)	1988 summer	1997 summer
ECAR	23.0	20.5
ERCOT	21.3	17.8
MAAC	19.0	20.3
MAIN	25.4	15.2
MAPP	28.4	20.9
NPCC	22.1	20.5
SERC	20.0	17.7
SPP	26.7	16.6
WSCC	31.5	25.5
Total NERC	24.3	19.9

SOURCE: North American Electric Reliability Council, *1988 Electricity Supply & Demand for 1988-1997*, October 1988, p. 24.

unit deratings or delays in operation, and higher than predicted demand growth rates.

Generation Reliability[9]

How a NERC region assesses generation reliability depends on the structural relationships between the regional council and its member systems and the degree to which various approaches are formalized by legal documents. Nearly all regions employ a probabilistic approach to generation adequacy analysis. The industry standard of 1 day in 10 years loss of load probability is widely shared.[10]

Significant parameters used in assessing adequacy include demand growth, load patterns, weather, potential slippage of in-service dates, transmission ties, and fuel and unit availability. Most regions encourage the use of a normal weather parameter in determining demand. With regard to capacity characteristics, all regions have a formal requirement for establishing the capacity rating. Also, all regions use either a probabilistic or judgmental evaluation of the effects on adequacy of operational capacity availability rates.

Capital Spending

The *Electric Light and Power Survey* of investor-owned utilities, cooperatives, and public power organizations indicated that regional capital investment will follow population and business growth trends. For example, the greatest spending activity will occur in the SERC and WSCC regions, which have the greatest capacity and the highest demand. Table 6-2 shows capital spending by region for the 1988-92 period.

Electricity Prices

Retail electricity prices vary by region and by class of service. Department of Energy (DOE) data for 1987 show that **average** retail residential electricity prices ranged from 6.89 cents per kWh in WSCC to 9.76 cents in Alaska and 9.69 cents in NPCC. Electricity prices for commercial and industrial customers also varied considerably. The NPCC and Alaska regions were the most expensive for commercial customers; industrial customers in Alaska, MAAC, and NPCC paid the highest prices. Table 6-7 shows the average retail electricity prices by class of service and region for 1986 and 1987.

NARUC's (National Association of Regulatory Utility Commissioners) 1986-87 winter survey of residential electric bills found that costs varied by as much as 300 percent regionally. Costs ranged from 4 cents per kWh in Spokane to 13.1 cents per kWh in New York. The average was 8.1 cents nationally.[11]

The Northeast and Pacific regions were the most expensive, while the Northwest and Rocky Mountain areas were the least expensive, according to NARUC.[12] Table 6-8 shows the ten most and ten least expensive service territories in the United States.

TRANSMISSION

NERC reports that there is no major transmission surplus in any region of the country. In MAAC, for example, the transmission system is reported to be fully loaded much of the time. Overall, new transmission line construction is declining. In fact, since 1985, the total amount of planned transmission facilities has declined, both in the United States and Canada. This decline is due in large part to the

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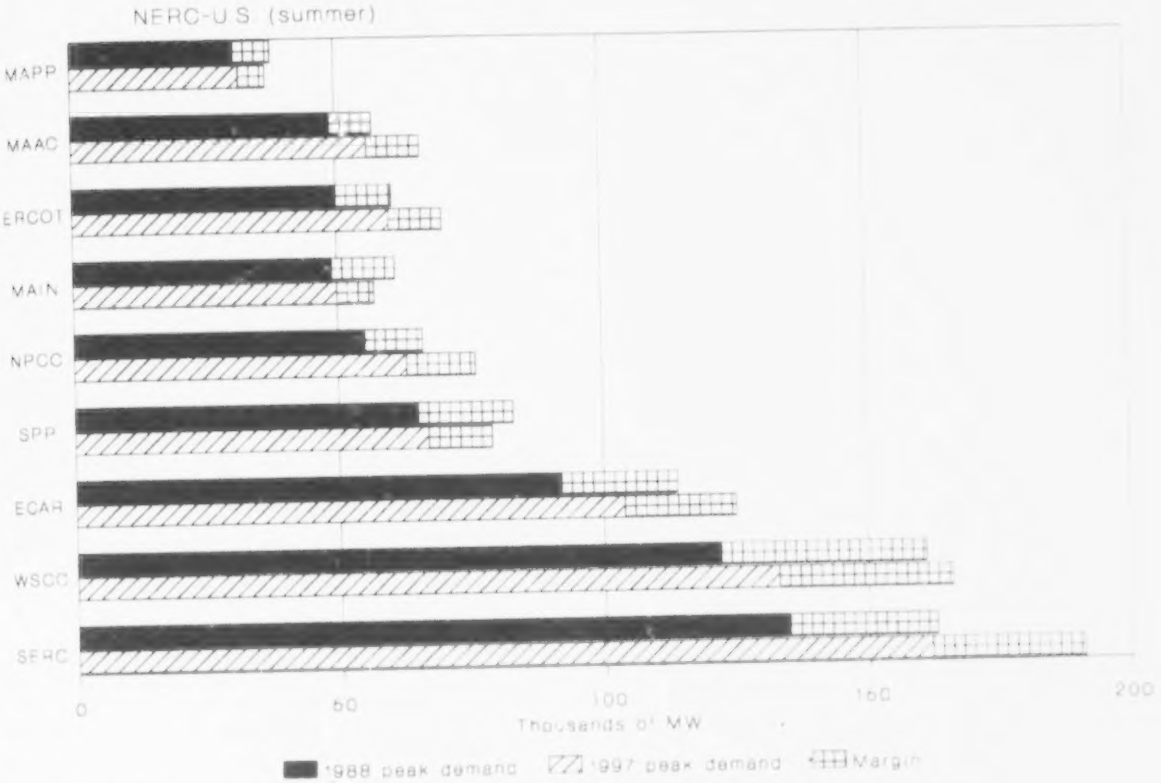
[9] Reliability Council Survey Responses, supra note 2, at p. 12.

[10] See discussion of 1 day in 10 years loss of load probability (LOLP) in ch. 4.

[11] The National Association of Regulatory Utility Commissioners (NARUC) 1986-87 Winter Survey of Residential Electric Bills, *Electric Light and Power*, vol. 66, No. 3, March 1988, p. 3.

[12] Ibid.

Figure 6-5—Estimated Margins at the Time of Regional Peak Demand



SOURCE: North American Electric Reliability Council

cancellation or deferral of new generation additions and their related transmission facilities (see figure 6-6). In addition, many utilities are giving greater emphasis to efforts to increase the capability of *existing* transmission systems because of the difficulties in siting and building new lines.

NERC expects that some transmission systems will continue to be heavily loaded by economy energy transfers, both within and among regions, during the 1988-97 forecast period. These transfers are expected to increase whenever sufficient fuel price differentials exist. For example, within regions, hydrogenerated energy will continue to be transferred from the Northwest area of WSCC to the Southwest area, provided there are no dry spells. Also, because of loop flow and parallel path phenomena, energy transfers among systems can increase loadings in other systems that are not parties to the transfer. MAAC's transmission system adequacy has been affected by New York Power Pool (NYPP) imports of Canadian hydropower, for example. To counteract these increases in interregional loading, NPCC and MAAC have reached an agreement on what constitutes normal and excessive use of each other's transmission system. The agreement includes the purchase and installation of phase shifting transformers near the New York/New Jersey border. OTA's case study "Importing Power from Canada to New England" illustrates this particular transmission problem.[13]

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[13] For more detailed information on the OTA case study, see Casazza, Schultz & Associates, Inc., "Case Studies of Transmission Bottlenecks," OTA contractor report, Nov. 30, 1988.

Table 6-6—Projected 5-Year Capital Expenditures (by NERC Region—millions of dollars)

Region	1988	1989	1990	1991	1992	5-year total
ECAR	3,303	3,204	2,756	2,460	2,022	13,745
ERCOT	1,676	1,264	1,188	1,184	1,502	6,814
MAAC	3,182	2,939	3,012	2,729	2,195	14,057
MAIN	1,897	1,490	1,428	1,370	1,503	7,688
MAPP	1,029	1,112	1,102	1,090	1,020	5,353
NPCC	1,876	1,726	1,782	1,800	1,518	8,702
SERC	7,189	6,766	7,030	6,703	6,224	33,912
SPP	1,463	1,360	1,310	1,389	1,369	6,891
WSCC	5,870	4,784	4,504	4,565	4,886	24,609
Total	27,485	24,645	24,112	23,290	22,239	121,771

SOURCE: *Electric Light & Power*, "Electric Utilities Will Increase Spending Plans Through 1992," vol. 66, No. 1, January 1988, p. 12.

Table 6-7—Average Retail Electricity Prices by Class of Service and Region, 1986-87 (cents/kWh)

NERC region	Residential	Commercial	Industrial
1987:			
ASCC	9.76	8.48	7.86
ECAR	7.08	6.68	4.44
ERCOT	6.68	5.81	3.99
HI	9.28	9.26	6.69
MAAC	9.05	8.32	6.05
MAIN	9.12	7.54	5.01
MAPP	6.96	6.22	4.34
NPCC	9.69	9.06	5.74
PRTER	7.51	9.83	7.78
SERC	6.96	6.55	4.67
SPP	7.26	6.64	4.37
WSCC	6.89	7.31	5.47
1986:			
ASCC	9.11	8.27	7.49
ECAR	7.13	6.78	4.63
ERCOT	6.70	5.91	4.20
HI	9.13	9.03	6.41
MAAC	9.38	8.83	6.52
MAIN	8.67	7.69	5.07
MAPP	6.83	6.27	4.53
NPCC	9.65	9.26	5.73
PRTER	6.89	9.17	7.27
SERC	6.95	6.58	4.73
SPP	7.36	6.78	4.60
WSCC	6.81	7.37	5.65

NOTES: Totals may not equal sum of components because of independent rounding.

SOURCE: Energy Information Administration, Form EIA 861, "Annual Electric Utility Report," preliminary data.

Assessing transmission constraints is a difficult task. Given the dynamic nature of bulk power transactions, the location and severity of transmission system constraints often change. The constraints that have been identified in various reports differ in nature and are caused by a variety of factors, as discussed in chapter 4. Because of these and other factors, no comprehensive list of bottlenecks has been developed. OTA has not investigated the cited incidences of transmission constraints.

The 1986-1987 National Governors' Association (NGA) survey of NERC regional councils, for example, identified a wide range of situations creating transmission limitations. However, many of these limitations may no longer be considered as such because conditions have changed since the time of the survey.

NERC has also listed impediments to transfer in its 1984, 1985, 1986, and 1987 assessments. Over that period some of those impediments have been solved or eased, while other projects remain delayed by regulatory actions. A 1985 ECAR/MAAC Coordinating Group report identified bottlenecks to the transfer of power from ECAR to MAAC. The primary restriction to ECAR-MAAC transfers, according to the report, has been voltage conditions in MAAC and eastern ECAR. Also, parallel path flows resulting from power transfers among utilities in the Northeast are cited as another limiting factor.

An OTA survey of some 23 utilities conducted in July 1988 found few cases of utilities having to restrict bulk power transactions or limit economic dispatch significantly because of transmission constraints. However, most respondents had to limit or operate outside optimal economic dispatch occa-

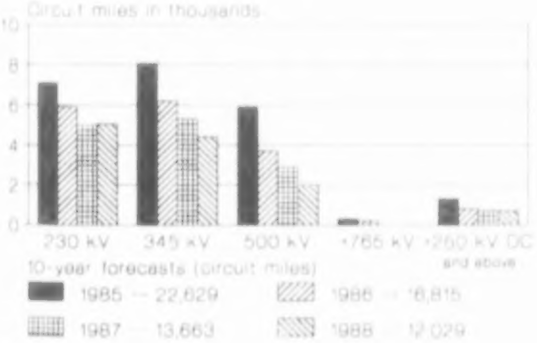
Table 6-8—The 10 Most Expensive and 10 Least Expensive Service Territories in the Continental United States

Company	State	Total bill	Average cost cents/kWh 500 kWh[a]	Rank
Ten most expensive service territories:				
Consolidated Edison Co. of N.Y.	New York	$195.91	$0.131	1
San Diego Gas & Electric	California	$179.91	$0.120	2
Long Island Lighting	New York	$177.56	$0.118	3
Philadelphia Electric	Pennsylvania	$175.87	$0.117	4
Orange & Rockland Utilities	New York	$168.77	$0.113	5
Texas New Mexico Power	New Mexico	$167.33	$0.112	6
Central Vermont Public Service	Vermont	$166.80	$0.111	7
Delmarva Power & Light	Virginia	$164.82	$0.110	8
Public Service Electric & Gas	New Jersey	$162.36	$0.108	9
Northern Indiana Public Service	Indiana	$162.09	$0.108	10
Ten least expensive service territories:				
Washington Water Power	Washington	$59.97	$0.040	191
Washington Water Power	Idaho	$62.73	$0.042	190
Idaho Power	Idaho	$63.17	$0.042	189
CP National Corp.	Oregon	$65.85	$0.044	188
Pacific Power & Light	Washington	$67.95	$0.045	187
Idaho Power	Oregon	$71.34	$0.048	186
Portland General Electric	Oregon	$72.84	$0.049	185
Pacific Power & Light	Montana	$73.32	$0.049	184
Puget Sound Power & Light	Washington	$75.74	$0.050	183
Minnesota Power & Light	Minnesota	$79.48	$0.053	182

[a] Based on customer usage of 500 kWh per month.

SOURCE: NARUC, "1986-87 Winter Survey of Residential Electric Bills," Electric Light & Power, March 1988, p. 3.

Figure 6-6—Planned Transmission Additions (NERC-U.S.)



SOURCE: North American Electric Reliability Council.

sionally. The utilities' responses generally were that the constraints were not significant enough to offset the costs of correcting them.

Demand for Increased Transmission Access

Determining which regions and utilities are most likely to request wheeling is a difficult task at best. However, several factors, such as price differentials, surplus generating capacity, and load diversity, indicate that transmission access requests are likely to increase in some regions. Among these regions are MAPP, MAIN, WSCC, and NPCC. Both MAPP and MAIN have abundant coal-fired capacity which could be exploited by selling to utilities outside the regions. MAIN also has substantial interregional transfer capability. Because of load diversity, base-load capacity surpluses, and large fuel price differentials, the WSCC subregions are likely to continue to take advantage of energy economy transfers. Also, the NPCC region, with its fuel price differentials and its growing reliance on Canadian generating resources, is more likely to seek additional transmission services.

A recent private consulting firm's report on wheeling indicated that if expanded transmission access is allowed, some regions could become major power exporters, and the total cost of electric generation and transmission in North America could be cut by $1.65 billion a year. Among the potential beneficiaries of an open transmission access environment could be the Rocky Mountain and the Arizona-New Mexico subregions of the WSCC, MAPP, and MAAC, according to the report.[14]

The NGA survey of NERC regional councils indicated that expanded transmission access could have an impact on reliability. ECAR and SERC respondents cited numerous problems with open access. These included scheduling generation and transmission maintenance, load dispatching problems, a decline in cooperation among utilities, and reliability impacts.[15]

The responses differed among utilities within regions, however. Those utilities that could actively participate in competitive bidding were less resistant to expanded access. Joint action agencies, regardless of region, noted that open transmission access would be beneficial for a number of reasons. Competitive and economic opportunities were the two reasons most often cited.

NONUTILITY GENERATION

Fuel use and costs, demand growth rates, and regulatory policies determine the potential for nonutility generation (NUG) in any region.

Determining the amount of actual NUG capacity on line or planned is difficult. There is no comprehensive and up-to-date source of information on total megawatts for plants in operation, under construction, or in the planning stage. While the Federal Energy Regulatory Commission (FERC) keeps records of applications for qualifying facility status,[16] it does not track operational facilities. Moreover, the Energy Information Administration also has not collected independent information that tracks the growth of nonutility generation. Consequently, little information on total NUG capacity is available. Those attempting to determine capacit often use different definitions, leading to furthe variations in data.

Estimates of current and future NUG capacit vary by region and by sector, as well as by estimator A number of reports have estimated current capacit and a few have even made projections. Thes include NERC, Edison Electric Institute, RC Hagler, Bailly, Inc., and the Gas Research Institute

Estimates of Total Nonutility Generation Capacity

Estimates of NUG capacity are being included, t a varying extent, in the NERC regional forecasts. The decision of how to treat NUG capacity addition rests with the local utility and regional council. NU capacity additions in the latest NERC projection were notable in WSCC, SERC, NPCC, and MAA regions. NERC projected a total of 27,656 MW o NUG capacity by 1997—about 22 percent of tot planned additions. Much of NERC's projected NU capacity, however, is characterized as "unknown, either as to location, fuel, or project. NERC esti mates current NUG capacity to be 7,741 MW a shown in table 6-9.[18] This NERC estimate mo probably understates the actual NUG capacity.

Based on a more extensive survey, the Ediso Electric Institute (EEI) also has calculated th amount of nonutility sources of generation, bot used internally in industry (self-generation) and sol to utilities (cogeneration). In 1986, EEI estimate that NUG capacity reached 25,321 MW, a 10 percer increase over 1985 figures. Cogenerators accounte for about 73 percent of total capacity or 18,448 MW About two-third's of the total cogenerated capacit are qualified facilities under the Public Utili Regulatory Policies Act (PURPA).[19] The industri with the greatest cogeneration capacity are th chemicals and paper and lumber industries, followe by the oil and gas and metal industries. Table 6-1

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[14] WEFA Group, "Power Wheeling in North America," *Electrical World*, vol. 202, No. 3, March 1988, pp. 13-14.

[15] Ohio Public Utilities Commission Staff, Summary of Utility Interviews, Aug. 12, 1988 (OTA contractor document).

[16] The number and size of PURPA QFs filed with FERC has increased markedly in recent years. In 1980, FERC received 29 applications for 704 M of PURPA qualified capacity. But by the third quarter of 1987, FERC received 3,571 applications for 58,717 MW of nonutility capacity.

[17] Utilities differ in how NUG capacity is counted. Some utilities report NUG facilities under total generating capacity, others treat the capacity a reduction in load, while still others do not include NUG capacity at all in reporting system capacity and generation.

[18] NERC, *1988 Reliability Assessment: The Future of Bulk Electric System Reliability in North America 1988-1997*, September 1988, p. 15.

[19] Edison Electric Institute, *Capacity and Generation of Nonutility Sources of Energy*, 1988, p. 11.

Table 6-9—Actual and Projected Nonutility Generation Capacity (summer MW)

NERC regions	Actual 1987	1988	1997
ECAR	148	192	2,308
ERCOT	2,956	2,536	2,506
MAAC	183	269	3,126
MAIN	0	0	12
MAPP	0	216	281
NPCC	874	1,517	4,572
SERC	961	1,526	5,910
SPP	31	47	582
WSCC	2,588	4,835	8,359
Total	7,741	11,139	27,656

SOURCE: North American Electric Reliability Council, 1988 Electricity Supply and Demand for 1988-97, October 1988, app. A, p. 20.

and figure 6-7 summarize EEI regional nonutility generation data.

Another report by a private consulting firm, "Profiles of Cogeneration and Small Power Markets,"[20] indicated that 1988 cogeneration and small power production capacity was 24,833 MW. An additional 38,345 MW are under construction or in design, according to the report.[21] Cogeneration projects outnumber small power projects by a margin of 3-to-1. And, in terms of capacity, cogeneration outnumbers small power by nearly a 5-to-1 ratio.[22]

The Gas Research Institute has been monitoring nonutility generation, particularly gas-fired cogeneration. The GRI report, *Impact of Cogeneration on Gas Use*, estimated cogeneration capacity at 19,000 MW in 1985. GRI expects 25,000 MW to be added by the year 2000.

Nonutility Fuel Use

Natural gas has been the predominant choice for NUG facilities. Recent lower prices and the availability of natural gas have contributed to its popularity among nonutility generators. Coal-fired and wood-burning facilities also provide significant amounts of NUG capacity. A large percentage of natural gas-fired capacity is in ERCOT (Texas), WSCC (California), SPP (Louisiana), and SERC. The SERC region also has a concentration of wood-burning cogeneration facilities. And MAAC (Pennsylvania) and NPCC (New York) have significant coal-fired NUG facilities. Combined cycle systems and boiler/steam turbine systems provide most of the capacity.

Regional Nonutility Generation Potential

All regions of the country have some level of nonutility generation. In the MAAC region, there is considerable potential for development of nonutility generation. NERC expects that nonutility generation will account for more than 40 percent, or 2,860 MW, of new capacity additions over the next 10 years.

According to a recent survey of qualifying facilities in the United States, cogeneration growth in the Mid-Atlantic has surpassed that of the Pacific and Gulf Coast areas.[23] New Jersey, New York, and Pennsylvania lead the nation with 13,262 MW of potential qualifying facility (QF) power, followed by the West South Central and Pacific regions.[24]

In its latest report *Electric Power Outlook 1988-2004*, the NYPP has indicated that a total of 2,577 MW of nonutility generation will be added between 1988 and 2002. This figure is more than twice the 1,081 MW predicted for the same period in NYPP's previous year's report. Without these nonutility generation additions, margins may not be adequate by the mid-1990s, according to the report.[25]

The importance of nonutility generation to meet demand in New England has been voiced by both NERC and the New England Conference of Governors. A recent New England Governors' Conference report indicated that cogeneration and small power production must play increasingly important roles if the New England States are to meet energy demand.[26] Also, NERC has indicated that the develop-

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[20] RCG Hagler, Bailly, Inc., *Profiles of Cogeneration and Small Power Markets*, 1988 edition.

[21] *Energy User News*, "Mid-Atlantic Area Forges Ahead in Cogeneration Development," vol. 13, No. 21, May 23, 1988, pp. 1, 8.

[22] *Electric Utility Week*, "Cogeneration Development This Year Seen Off A Bit, But Still Active," Apr. 25, 1988, p. 12.

[23] *Energy User News*, supra note 21.

[24] Ibid.

[25] *Electric Utility Week*, "Cogeneration, Demand Cut, Nuclear Seen Necessary To Get NYPP to 2004," May 30, 1988, p. 11.

[26] *Cogeneration*, "Big Role for Cogeneration in New England's Energy Future," vol. 4, No. 1, January-February 1987, p. 28.

Table 6-10—Nonutility Generating Capacity by Region

Region	States	NERC regions full/partially included	1986 nonutility capacity	Percent cogeneration	Percent cogeneration qualified
New England	ME, VT, NH, MA, CT, RI	NPCC	1,404 MW	48% (667 MW)	61%
Mid-Atlantic	NY, NJ, PA	NPCC, MAAC	1,552 MW	67% (1,045 MW)	72%
East North Central	IL, IN, MI, OH, WI	MAIN, ECAR, MAPP	2,840 MW	69% (1,950 MW)	23%
West North Central	IA, KS, MN, MO, ND, NB, SD	MAPP, SPP	661 MW	36% (239 MW)	36%
South Atlantic	DC, DE, FL, GA, MD, NC, SC, VA WV	MAAC, ECAR, SERC	3,989 MW	84% (3,351 MW)	61%
East South Central	AL, KY, MS, TN	SERC, SPP	1,104 MW	96% (1,064 MW)	58%
West South Central	AR, LA, OK, TX	SPP, ERCOT	7,751 MW	93% (7,231 MW)	78%
Mountian	AZ, CO, ID, MT, NM, NV, UT, WY	WSCC, MAPP	420 MW	55% (233 MW)	52%
Pacific	CA, OR, WA	WSCC	4,687 MW	38% (1,816 MW)	97%
Alaska			644 MW	100% (644 MW)	
Hawaii			270 MW	77% (208 MW)	
Total			25,321 MW	18,448 MW	

SOURCE: Edison Electric Institute, *Capacity and Generation of Non-Utility Sources of Energy*, July 1988, pp. 26-27.

ment of nonutility generation is important to ensuring the NPCC's supply adequacy over the next 10 years. Between 1988 and 1997, nonutility generation capacity is expected to increase by 27 percent in New England and by 44 percent in New York, according to NERC.

ECAR expects nonutility generation to increase from 168 MW in 1988 to 1,329 MW by 1991. West Virginia is one of the States within this region that is taking a hard look at cogeneration as part of its long-range energy plan to make the State a regional electricity exporter. However, the State's cogeneration potential may be limited by overcapacity and low avoided-cost factors and by limitations on available transmission capacity to potential consumers in Northern States.[27]

ERCOT produces a great deal of nonutility generation, almost all of which is gas-fired. NERC projects that 2,537 MW or 5 percent of 1988 summer peak capacity resources will be supplied by nonutility generators, mostly cogeneration. Without the projected nonutility generation capacity additions, the region's 1997 capacity margin would decrease from 17.8 percent to 14.2 percent, according to NERC. Some of this cogenerated electricity was wheeled to utilities other than the connecting utility. NERC indicates that the figure may be as high as 60 percent of NUG capacity under contract within ERCOT.

Other projections also show that cogeneration will make a significant contribution to capacity in Texas. The Texas Public Utilities Commission assembled a data base of State cogeneration projects that were either in operation, under construction, or being planned for service before the end of 1988. The data showed that Texas should have about 9,500 MW of cogeneration capacity in 1988.[28]

The largest number of cogenerators in Texas are in the oil, gas, and chemical industries. These industries have great cogeneration potential, as well as financial and political clout. Texas has taken steps to increase cogenerators' access to transmission lines to move power to nonlocal utilities, but state law explicitly prohibits retail or self-service wheeling.

SERC, the fastest growing region, expects about 6,200 MW of new nonutility generation by 1997. According to NERC, nonutility generation will continue to be an increasingly important source of new capacity for some systems of SERC. While nonutility generation is not expected to significantly

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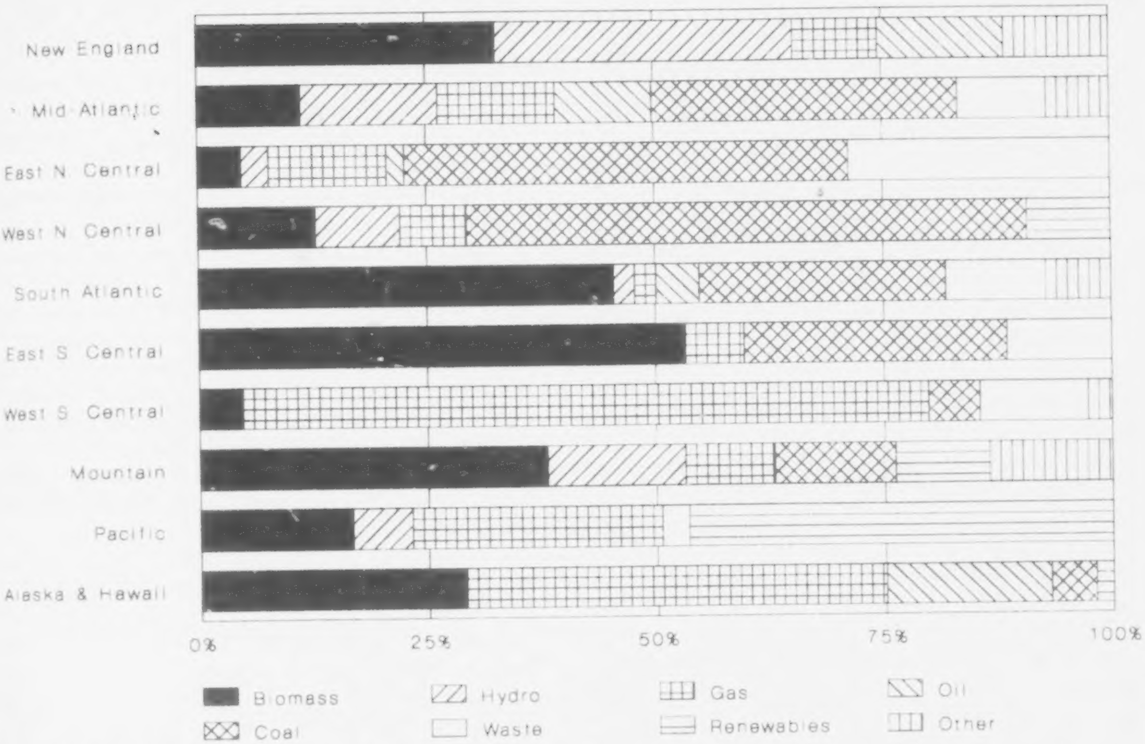
[27] *Cogeneration*, "In the States," vol. 4, No. 3, May-June 1987, p. 55.

[28] GRI, *Impact of Cogeneration on Gas Use in the Industrial and Electric Utility Sectors*, January 1986, p. ES-27.

Figure 6-7—Nonutility Fuels, 1986



Biomass includes agricultural waste, landfill municipal solid waste, and wood.
Waste includes anthracite culm, blast furnance gas, coke oven gas, digester gas, petroleum coke, refinery gas, refinery oil, sulfur combustion, waste gas, and waste heat.
Other includes nuclear, fuel cell, and projects which did not identify primary energy source.

SOURCE: Edison Electric Institute, *1986 Capacity and Gneration of Non-Utility Sources of Energy* (Washington, DC: July 1988).

penetrate the TVA service area, it is expected to contribute significantly to the Virginia-Carolina Region's (VACAR) capacity needs during the next decade. For example, Virginia Power signed seven contracts in mid-1987 for 1,181 MW of cogenerated power. The utility expects that 75 percent of its new capacity needs by 1990 must be met by cogenerated sources.[29] In addition, in March 1988, Virginia Power solicited bids for 1,750 MW of additional capacity. The solicitations generated interest from potential suppliers of about 27,000 MW, including some cogeneration and coal waste projects.[30] Detailed information on Virginia Power's bidding system can be found in box 5-B in chapter 5.

From 1988 through 1997, nonutility generation capacity additions represent about 31 percent of WSCC's planned additions. NUG additions will account for almost 5 percent of the region's total 1997 resources, according to NERC.

Of the four WSCC areas, the California-Southern Nevada Power Area is projecting the highest growth in nonutility generation. California leads the WSCC region in projected NUG additions. NUG capacity is forecast to increase from 1,740 MW in 1987 to 6,768 MW by 1997. These estimates differ significantly from those reported by the California Independent Energy Producers (CIEP). Based on the cogeneration/small project quarterly reports issued by California utilities, CIEP indicates that 5,218 MW of QF generation was on-line in California, as of the end of 1987. An additional 11,964 MW are under contract or in the discussion stage.[31] The increase in NUG facilities have been stimulated by the California regulatory commissions' interpretations of PURPA. Most of these facilities are base-load in nature, and many are small, low-voltage units. Because of the oversupply of NUGs in the mid-1980s, the California Public Utility Commission suspended long-term contract offers. California has since developed a bidding system for acquiring long-term energy and capacity. (See box 5-C for more detailed information on the California bidding system.)

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[29] *Cogeneration*, "Virginia Power Deals for 1,181 MW of Cogenerated Power for 1990 Delivery," vol. 4, No. 4, July-August 1987, p. 18.

[30] *Energy Daily*, "Competitive Bidding: The 30% Solution," vol. 16, No. 99, May 24, 1988, p. 1.

In contrast, growth in NUG capacity has been relatively slow in the Rocky Mountain Power Area. This may be attributed to the substantial amount of surplus coal-fired generating capacity available within the area, which results in low avoided costs. However, a recent flurry of QF proposals in Public Service Colorado's (PSC) service territory could increase the region's NUG capacity. PSC claims that if all the potential projects enter service, it would be buying 1,149 MW of nonutility generation by 1991—784 MW more than it had projected. This situation led the Colorado Public Service Commission to suspend the signing of new QF contracts in late 1987 for 60 days.[32] Colorado has since approved a bidding program for new supplies for PSC.

SPP anticipates nonutility generation capacity to reach 582 MW by 1997, or 0.9 percent of total capacity. Most NUG capacity is expected to develop in the West Central subregion of SPP. The NERC estimate probably understates current NUG capacity for this region. EEI, for example, reported that Louisiana alone accounted for 7 percent (1,972 MW) of the total U.S. nonutility generating capacity in 1986.

The planned use of nonutility generation in MAIN is modest compared to other regions. Nonutility generation is included as installed capacity in 1988 and only 12 MW is projected by NERC in 1997. The region's substantial low-cost coal-fired and nuclear capacity has dampened nonutility growth.

Nonutility generation also is a minimal part of MAPP's resource plans. NERC forecasts that by 1997, nonutility generation will represent less than 1 percent of total capacity.

Regional Experience With Nonutility Sources of Power

The recent growth in NUG capacity has benefited both utilities and customers. According to EEI, electricity sales to utilities from nonutility sources have increased six-fold since 1979. Almost all of the sales have been to the investor-owned segment of the industry. In 1985 and 1986, receipts grew at annual rates of 46 and 44 percent respectively, EEI reports.[33] But, this rapid growth has also raised some concerns by NERC over reliability. Some of these concerns include responsibility for reactive power support, voltage control, and the additional requirements imposed on utilities for supply planning uncertainty, transmission loading problems, and integration into utility operations. NERC and purchasing utilities face new challenges in how to handle the additional planning uncertainties of possible nonperformance or noncompletion of planned nonutility generation. To some extent, these concerns will be alleviated as the industry gains more experience in effectively integrating nonutility sources of supply.

Some regions have considerable experience in developing working arrangements for dealing with NUG power, including bidding, long-term contracts, pricing terms, and dispatchability provisions. For example, California regulators can require new cogeneration plants to follow load through the use of power-purchase contracts and regulation. Recently, the California Energy Commission has required that new 50+ MW cogeneration units agree to cycle as a condition of their siting permits. As of mid-1988, two "dispatchable load" contracts were in place and others were expected.[34]

According to NARUC, 24 States have adopted or plan to adopt competitive bidding as a means of procuring QF power. Among them are Massachusetts, Maine, and California. Nonprice factors, such as dispatchability, also can be considered in the bid evaluation. Michigan and Vermont are considering price-bidding systems. Washington State has proposed a bidding system for investor-owned utilities as a means of securing supplies from QFs under PURPA. Non-QF capacity would not be included under the State's new rule. The Washington proposal is modeled on the system in effect in Massachusetts.[35]

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[31] California Independent Energy Producers, California Summary, Alternative Energy Projects (4th Quarter 1987).

[32] *Electric Utility Week*, "Independent Power," Dec. 28, 1987.

[33] Edison Electric Institute, supra note 19, p. 1.

[34] *Electrical World*, "Cogeneration: Threat or Opportunity?" vol. 202, No. 7, July 1988, p. 66.

Other States—Connecticut, Rhode Island, and Virginia—have adopted or allow nonprice competitive systems. The nonprice systems are used for a number of reasons, which include encouraging QF development in States and avoiding the possibility of conflict with the legal requirements of PURPA. Several additional States are examining bidding systems: Idaho, Nevada, New Hampshire, New Mexico, Oregon, Pennsylvania, and Utah.

REGIONAL DIFFERENCES AND INDUSTRY CHANGE

The impacts of proposed regulatory and structural changes will differ for individual regions, States, and electric systems because of the differences among existing systems and the wide range of possible conditions and reactions that must be taken into account. Among the most significant regional influences will be:

- adequacy of electric power supplies to meet demand;
- transmission access including availability, adequacy, and pricing;
- the regulatory climate;
- the competitive environment; and
- impacts on retail customers.

These regional variations will strongly determine how well and how quickly proposals for change can be implemented.

Adequacy of Supply

Utilities base their assessments of power supply adequacy on past experiences and future assumptions about the interplay of electricity demand and growth rates and available power supplies. Changes in electricity demand are reflected in both net energy for load and peak demand and are influenced by weather patterns, economic activity, and the effectiveness of load management and conservation strategies. Power supply considerations include installed generating capacity, reserves margins, capacity availability, and the potential for bulk power purchases.

These assessments are inherently uncertain, and to counter the risk of underestimating demand, utilities in the past may have overstated potential demand growth in establishing their capacity needs (including a typical 15 to 20 percent capacity margin). In recent years, however, some utilities have tended to project 10-year demand growth rates that trail actually experienced increases in electricity use. At these lower demand growth rates, NERC currently forecasts that all its regions will have adequate electricity supplies through the mid 1990s. But if demand growth rates are higher than forecast, many regions could need additional capacity earlier than forecast. According to various analyses, areas with potential shortfalls in capacity margins at annual average growth rates exceeding 2 percent include MAAC, MAIN, MAPP, NPCC, SERC, and SPP.[36] The analyses were not in agreement on all regions, however.

In addition to differences in demand growth, various capacity availability factors can influence whether existing or planned generating facilities can be used to supply power when needed. In addition to the routine unavailability for regularly scheduled maintenance and the unpredictable but inevitable random forced outages, system characteristics and external events can affect capacity availability and reduce system reliability. For example, under some conditions regions that are heavily dependent on a particular fuel or generating source could face capacity availability restrictions that exceed their capacity margins because of unforeseen fuel shortages or new environmental or safety requirements. This vulnerability may create a sudden need for replacement bulk power sources.

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[35] *Electrical World*, "Bidding Systems: Who Has Them and Why," vol. 202, No. 3, March 1988, pp. 15-16. Based on National Independent Energy Producers report "Pricing New Generation of Electric Power, A Report on Bidding."

[36] See for example, U.S. Department of Energy, Deputy Assistant Secretary for Energy Emergencies, "Staff Report: Electric Power Supply and Demand for the Contiguous United States 1987-1996," DOE/IE-0011, February 1988; Amy Abel, "Canadian Electricity, the U.S. Market and the Free Trade Agreement," Congressional Research Service Report 88-427 ENR, July 5, 1988.

In ECAR, MAIN, MAPP, and SERC, over half of the installed generating capacity is coal-fired. In ECAR coal plants accounted for over 90 percent of electricity generated in 1987. If new environmental protection requirements are legislated to reduce emissions associated with acid rain and global warming, many of these coal plants, particularly the older ones, would be directly affected. In the extreme, compliance with emissions reduction strategies could shut down some of these plants temporarily or permanently.

ERCOT, NPCC, and SPP are heavily dependent on oil and gas generating capacity and would suffer adversely in the event of shortages or rapid price increases in oil and natural gas.

During 1988, drought and low flow conditions reduced the availability of hydroelectric plants in the West and South. Low flow conditions can reduce availability of water for cooling steam plants leading to a downrating of their capacity.

Safety considerations requiring the curtailment or shut down of nuclear plants could seriously affect plant availability in MAIN, MAAC, MAPP, SERC, NPCC and WSCC, thus reducing the adequacy of electric supplies for these regions.

Regions or systems with a higher proportion of aging plants may suffer a decline in availability if, as expected, the older plants require more frequent maintenance. In ECAR, MAIN, NPCC, and SPP more than a quarter of all installed capacity in 1995 will consist of fossil-fired plants that are more than 30 years old. These "geriatric plants" may, however, prove to be valuable resources as some may be very cost-effective peaking units and others may be suitable candidates for life-extending refurbishment to provide power at lower costs than equivalent new plants. Some nuclear plants may face more frequent operating restrictions as they age.

Bulk power purchases may be an attractive alternative to building new utility capacity for systems with concerns over supply adequacy and/or reliability. The existence of a range of competitive suppliers and the availability of transmission ser ices to move the power would seemingly off benefits to these systems and regions. If the benefi offered are perceived to outweigh potential risks, is likely that utilities and regulators would receptive to proposals for a more competitiv industry structure.

Utilities in areas without surplus capacity ar likely to be less resistant to competitive supplie both because of the need for reliable least-cos capacity and because the competition covers incre ments of new supply and does not directly threate the loss of existing markets. There also will be regional incentive to work out transmission acces and other difficulties. If, however, a region does not need capacity but in fact has a surplus of generating capacity, expanded competition could have potentially adverse consequences for traditional regulated utilities and their ratepayers in loss of market share, bypass, and additional purchase obligations. On the other hand, competitive markets might provide a mechanism to sell some of their existing surplus power and capacity.

Transmission Access

Transmission access considerations include the terms (including price) under which a party will be permitted to move power over the grid and the conditions that influence the availability and adequacy of the transmission system.

Although theoretically possible because the necessary physical connections are in place, it is not always possible in practice to move large amounts of bulk power between any two points in the United States over the existing transmission system. This situation is not likely to change in the near future for several reasons. First, available transmission capacity is limited and much of this is committed under long-term contract. The existing transmission lines in most areas of the country are already heavily loaded with firm and economy energy transactions according to utility industry sources. Second, the United States is not physically integrated on a single grid. The lack of extensive interties between the three separate interconnections (not to mention Alaska and Hawaii) will limit the extent of any competitive markets that may evolve. This means, for example, that surplus power from Texas (ERCOT) will not easily be able to compete in markets in Arkansas, Louisiana, and Oklahoma (SPP-SERC), or in New Mexico-Colorado (WSCC). Third, transmission capacity usually cannot be added quickly. It takes time to design, site, and build new or expanded transmission facilities, and sometimes local opposition is intense. In extreme cases, it can take several years or more to put a new line in place once a need and cost effectiveness have been clearly established. Finally, the as yet unestimated costs of building and maintaining national or regional grids with ample excess transmission capacity to accommodate a broader range of potential power transfers are likely to be high, and perhaps unnecessary for most needs.

In areas where the transmission system is already heavily loaded, it has been asserted that at times desirable bulk power transactions could not be accommodated without exceeding minimum system reliability operating guidelines. Comprehensive assessments of the locations and the extent of such constraints have not been undertaken, nor are any estimates available of the potential savings foregone. A frequently cited example of transmission constraints is that surplus coal-fired power from the Midwest cannot easily move to Northeast and Southeast utilities that may be looking for additional supplies because of transmission constraints or bottlenecks in ECAR and MAAC. These constraints have been partially attributable to the heavy use of lines under long-term "firm" energy commitments, power pool transactions, and parallel flows from Canadian-U.S. transfers in NPCC.

Even if transmission capacity is available, without some sort of provision for assuring transmission access, some line owners may be unwilling to open up the grid to wheel power for others. The possible reasons for refusals are many and include: to reserve available capacity for the line owner's opportunities to sell or buy power at attractive prices; to maintain redundant transmission capacity to enhance system reliability and flexibility; to restrict access to its market area and customers by actual or potential competitors; and/or an unwillingness to undertake the burdens of additional regulatory, accounting, and operating requirements that may be involved in opening up the system. Some analysts note that lack of effective economic incentives for wheeling services or adding transmission capacity under the existing institutional and regulatory treatment of wheeling arrangements is a major impediment to increasing transmission access.[37]

Existing regional transmission relationships among utilities through power pools, coordination agreements, and Federal power marketing systems could help the development of an effective transmission access system. These ongoing relationships could become the foundations for the essential institutional structure, precedents, and arrangements for executing wheeling transactions to move power and make deals. Without the necessary institutional protections, greater competitive pressures and the attractiveness of profitable off-system bulk power sales could lessen the characteristic cooperation of joint operations and power pools. Growing rivalry among regional utilities could discourage sharing of information and generating and transmission resources, adversely affecting reliability and power pool operations. Competitive pressures could yield lower capacity margins and reduced maintenance of facilities in an effort to cut costs. But, at the same time, generators would continue to share a common direct interest in maintaining optimum system operations, which perhaps could counter behavior that might imperil current reliability levels.

The extent to which interregional or intersystem transmission access or availability will become more or less critical in the future cannot be predicted with any certainty. The existing demand for and interest in transmission services are the result of several conditions:

- current capacity surpluses and shortages,
- differences in bulk power prices/costs,
- relative locations of load centers and generating plants,
- availability of and eligibility for wheeling services, and
- industry structure and practices.

Because many of the above conditions can change over time, a significant share of the present demand for transmission services could be transitory and could disappear in a shorter time than that needed to

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[37] National Regulatory Research Institute, *Some Economic Principles for Pricing Wheeled Power* (NRRI-87-7) August 1987; National Regulatory Research Institute, *Non-Technical Impediments to Power Transfers* (NRRI-87-8) September 1987.

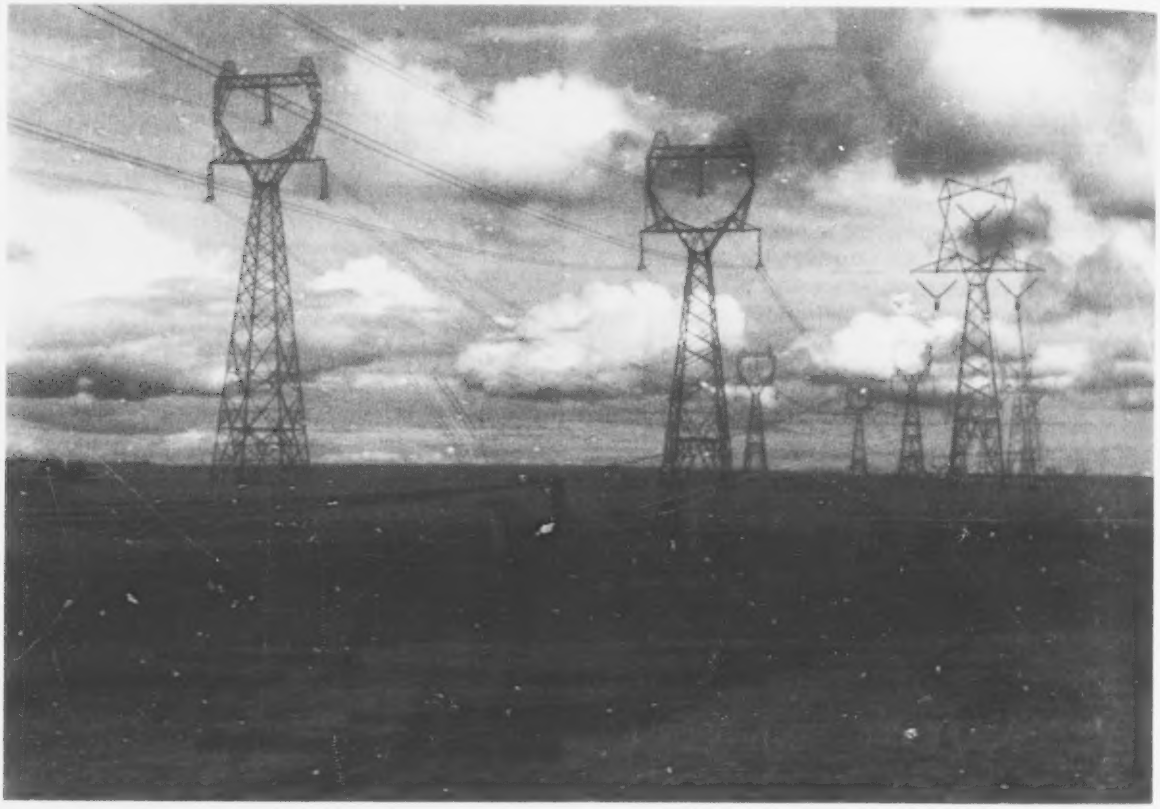

Photo credit: Casazza, Schultz & Associates, Inc.

A high-voltage transmission corridor

plan for and recover investments in additional transmission capacity.

For example, if new generating sources locate close to load centers and within the local transmission grid or service areas of customer utilities, the need for some long-distance firm and economy power transfers would be reduced and the transmission system could at least in part revert to its role as a means of providing emergency power. There is some evidence that utilities are giving preference to generating capacity additions that reduce demands on the transmission system.[38]

Changes in fuel costs could eliminate much of the bulk power price differentials driving many wheeling transactions. For example, when oil prices were very high, a transmission interface was built to tie the surplus coal-fired generation in the Southern Company system to oil and gas-fired utilities in Florida. With lower oil prices and new generating capacity on line, power purchases from the Southern Company are sharply down and the interface is loaded far below its previous levels (one of the very few examples of acknowledged surplus capacity).

While some portion of transmission demand could be transitory, the electric power industry's structure and practices assure that the extensive transmission network will continue to be needed under various future scenarios. Joint operations and power pooling arrangements are motivated by reliability and economic concerns. Strong transmission networks are needed to move power to load centers from distant generating sites. Long-term contracts and other arrangements are in place to move power from coal plants in Arizona and New Mexico west to California, and from hydroelectric projects in Quebec south to New England and New York. Other agreements exist to take advantage of seasonal load differences, such as the current and planned long-term power contracts to move power south from the Pacific Northwest in summer and north from California in winter. These transactions will be of concern not only to the parties involved but also to other utilities on the interconnected systems because of their inevitable influence on the grid.

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[38] Texas Utilities is adding combustion turbines to its system at remote system points rather than at a central location in order to avoid the need for additional transmission. *Electrical World*, vol. 202, No. 7, July 1988, p. 31. Location has frequently been acknowledged as an important "nonprice" factor in evaluating competing bids.

Many utilities, particularly in the public sector, rely on bulk power purchases to supply all or part of their requirements. These utilities (or distribution-only utilities under some competitive scenarios) would still seek lowest cost supplies for their customers and will press for wheeling services so that they are not necessarily tied to a single monopoly supplier.

Transmission concerns will remain even if the extent of economy transfers diminishes, growing demand absorbs surplus capacity, and new generating capacity is built. Utilities, generators, and customers will share a common interest in the reliability and security of electric power supplies. New patterns of bulk power transactions and the entrance of nontraditional power suppliers have accelerated the breakdown of the old model of the regionally isolated integrated system generating and transmitting power solely within its exclusive territory to serve the needs of (captive) customers.

The Regulatory Environment

The regulatory environment created by State and Federal policies could advance or hinder a shift to a more open, competitive electric power industry. A number of States have already allowed utilities under their jurisdiction to use competitive bidding or negotiation to secure new power supplies and to establish avoided costs—thus advancing competition.[39] The Federal Energy Regulatory Commission (FERC) has proposed rules to allow the use of competitive bidding to set PURPA avoided-cost capacity payments and to encourage the entry of independent power producers. Both of these measures are intended to encourage competition. However, some State regulators have criticized the FERC proposals as actually hampering and delaying the growth of competition by preempting State initiatives in the area and requiring extensive changes to many State regulatory programs. State regulators and others have criticized the lack of explicit FERC guidance or rulemaking on transmission access and pricing issues as constraining the growth of competitive markets by shutting out potential buyers and sellers.

Some options for reform of the existing system could impose additional burdens on regulators, consumers, and State jurisdictional utilities (such as, for example, the preapproval process in scenario 1 and the needs determination and bidding programs of scenario 3). The increased involvement of regulatory agencies is a necessary component of the reforms intended to avoid the risks of regulatory disallowance under existing law.

New Federal initiatives could also diminish the effectiveness of State and local programs in consumer representation and protection, siting, alternative energy technologies, conservation, and energy efficiency.

The most significant area of regulatory policy is establishing the appropriate and respective roles of State and Federal regulators. This task has been made more difficult by recent FERC actions and

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[39] At least 24 States have adopted or are developing variations of competitive procurement programs for some or all of regulated utilities power needs. Among the States that have adopted bidding programs are: Virginia, Connecticut, Maine, Massachusetts, New York, California, Texas, and Colorado. Some have imposed wheeling requirements on instate utilities in conjunction with PURPA implementation. Many States have already moved to correct early difficulties with PURPA avoided costs. States' anticipatory oversight of utilities' generation and transmission resource planning increasingly encourage consideration of competitive and regional needs. See Mary Nagelhout, "Competitive Bidding in Electric Power Procurement: A Survey of State Action," *Public Utilities Fortnightly*, vol. 121, No. 6, Mar. 17, 1988, pp. 41-45.

U.S. Supreme Court decisions.[40] The split jurisdiction over utility regulation has long been an area of tension and source of uncertainty. Recent State efforts might be stymied by Federal preemption of their regulatory programs if existing initiatives were not grandmothered under new Federal rules. The limited State jurisdiction over transmission access also tends to undercut State implementation of competitive strategies. As noted in chapter 3, it is possible under some alternatives to delegate to the States certain responsibilities for transmission jurisdiction now resident at FERC. This could perhaps be coupled with a right of appeal to FERC or the Federal courts. One advantage of such an arrangement is to move decisions on system use, retail wheeling, and prudence back to those who must weigh competing local interests in approving resource plans, siting, and retail rates. In cases involving interstate transactions, there might be some mechanism for consultations between States or referrals to FERC. This could foster more comprehensive State and regional cooperation on transmission issues.

The confidence of the affected parties in the decisions of regulatory authorities or in the mechanisms that substitute for the operations of the regulatory system will be very important for the success of initiatives for a more competitive system. If, for example, consumers believe that their interests are not adequately protected, or perceive that utilities or independent power producers are unduly enriched by the new arrangements, their political opposition to the alternative may well doom its long-run success.

Competitive Environment

The competitive environment in a utility system or region will be a major influence in how rapidly and successfully any shift toward a market-based sector will proceed. There are many tangible and intangible factors that will shape the competitive environment, and these will likely be tied to site-specific and regional conditions.

The existing power system infrastructure and institutional arrangements could either help or hinder market entry and competition in a State or region. If there are one or more dominant utilities with control of critical facilities, such as low-cost generating facilities, distribution companies, or transmission systems, new entrants could be deterred from competing in that market area. If most bulk power supplies are already committed under long-term contracts or there is a surplus of existing low-cost power, opportunities to compete for new power supplies could be limited. But a demand for power or a specialized niche for potential competitors can create market opportunities that attract competitors. In the Northeast, with the support of State regulatory commissions, many utilities are actively soliciting bids for capacity increments from QFs and other suppliers. In four States (Connecticut, Maine, Massachusetts, and Virginia) that have completed competitive solicitations, the bids far exceeded the amount of power sought.

The availability of sufficient transmission capacity to support the growth of a competitive regional bulk power market is also important. Mandatory wheeling authority would not be of much help to guarantee transmission access if the system is already fully loaded.

Impacts on Retail Customers

Impacts on retail customers will ultimately determine the acceptability of any electric power industry structure and its longevity. The most significant effects will be in retail electricity prices and changes in reliability or quality of utility services. Local experiences and perceptions will be different. In some regions, a move to a more competitive structure may be perceived as a net benefit, in others it may become the focus of all dissatisfaction with electric power system operations and prices. If the latter is the case, consumers will pressure their elected officials to reform the system.

In weighing various proposals for change, regulators will have to deal with a range of equity considerations in the areas of public service and accountability, distribution of costs and benefits, and system reliability. Often there will not be adequate information available to respond fully to these concerns and the determination will rest on the best judgment of decisionmakers.

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[40] The recent expansion of Federal preemption is seen in the FERC decision in Orange and Rockland Utilities, Inc., 92 PUR 4th 1988, and the U.S. Supreme Court's decision in *Mississippi Power & Light Co. v. Mississippi ex rel. Moore, Attorney General of Mississippi et al.*, No. 86-1970, June 24, 1988.

OTA SCENARIOS AND REGIONAL IMPLEMENTATION

The impacts of OTA's scenarios, as with similar proposals, will depend on the characteristics of the individual utility systems and State regulatory bodies. The detail required to analyze and predict these potential impacts lies well beyond the scope of OTA's review of the technical feasibility of implementing the scenarios. Nevertheless, the local impacts will create significant considerations for policy makers. It is notable that none of these impacts has been examined in any systematic, comprehensive way in the various proposals that OTA used in developing these scenarios.[41] Even FERC did not provide any substantive analysis of the potential impacts of its recent Notice of Proposed Rulemaking (NOPR) beyond its assumed "worst case" environmental impacts analysis, which was driven by arbitrary assumptions on fuel use, technology choice, and generation by independent power producers.[42] A further confounding problem in ascertaining potential impacts is uncertainty over how wheeling transactions will be priced. Although transmission pricing was outside the scope of this assessment of technical feasibility, it will be highly determinative in shaping the extent of and participation in competitive markets under all scenarios.

Scenario 1

Scenario 1 would modify the existing State regulatory programs to require State preapproval for construction of new utility capacity with prudence determinations at strategic milestones in each project.[43] The scenario would also include Federal and State regulatory changes to remove some of the problems encountered in early implementation of PURPA, such as limiting the categories of eligible facilities and bringing PURPA energy and capacity payments more into line with utilities' actual avoided costs.

Under this scenario, as in others, major impacts will be local and utility-specific. The reduced regulatory risk of disallowance may provide an incentive to reluctant utilities to identify and construct needed capacity earlier than they might otherwise plan under a risk aversion strategy. It is not known how many utilities, if any, would fall into this category, where they are located, and how much needed capacity would be affected.

Scenario 1 would affect the regulatory systems in all States,[44] although the potential disruption of State programs may be tempered somewhat by the fact that many States already have incorporated elements of scenario 1 in their State programs.[45] These key elements include prior review and certification of need for new capacity and review and approval of utilities' resource plans. The existing precedents of regulatory standards for prudence could be applied in a periodic milestone review. Most States have allowed recovery of prudent investment on abandoned plants.

Although no State has adopted the equivalent of scenario 1, Massachusetts recently established a preapproval process for new non-QF capacity that would, among other things, set the allowed rate of return in advance of project construction.[46] More than half the States have a least-cost planning program in place or under development. Most States require utilities to submit long-range plans for generation and transmission requirements.[47] More than 24 States already have approved bidding programs and others currently are considering them. Most State programs provide for regulatory review and approval of resultant utility contracts. (Some specifically defer decisions over the prudence of the power purchase arrangement until the time of power delivery, however.)

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[41] One exception to the general lack of detailed analysis of the more popular schemes for change is found in the review of various deregulation scenarios by Paul L. Joskow and Richard Schmalensee, *Markets for Power: An Analysis of Electrical Utility Deregulation*, (Cambridge, MA: The MIT Press, 1983). They too were somewhat hampered by the unavailability of data with which to conduct any detailed analysis.

[42] Federal Energy Regulatory Commission, Draft Environmental Impact Statement on Regulations Governing Independent Power Producers (RM88-4-000) and Regulations Governing Bidding Programs (RM88-5-000), June 1988.

[43] It is conceivable that Federal legislation (like PURPA) could require States to adopt a preapproval structure within FERC guidelines, but leave the details of implementation to the States. Legislation could also require that FERC follow State planning and preapproval processes or confer with State regulators in considering rate requests and rates of return for FERC jurisdictional utilities.

[44] Except perhaps Nebraska which relies solely on public power and has no Statewide ratesetting body. Texas, Alaska, and Hawaii are also States where the impacts on existing regulatory programs are uncertain because they are not generally connected to the rest of the interstate electric power systems and thus are not fully under FERC jurisdiction. The changes in PURPA rules would, however, affect State PURPA regulatory programs and unregulated utilities.

[45] See discussion in ch. 3 and "Transmission Line Certification and Siting Procedures and Energy Planning Processes: Summary of State Government Responses to a Survey by the National Governors' Association Task Force on Electricity Transmission," prepared by staff members of the Public Utilities Commission of the State of Ohio and of the West Virginia Public Service Commission, OTA contractor report, July 1988 (hereafter State Government Survey responses).

To accommodate this multi-stage regulatory process, State agencies will have to increase staff and budgets or divert resources from other activities. Utilities also would see some increase in their regulatory activities. The greatest regulatory impacts would be felt in States in the West and Southeast that typically have State regulatory programs with a more traditional, reactive approach to ratemaking and that do not have much involvement in anticipatory oversight or review of utilities' resource planning.[48]

The scenario would give States the flexibility to allow experiments in competition for bulk power supplies as they wished. Under scenario 1, transmission access remains largely voluntary under existing law. Depending on whether or not FERC addresses the issue, the lack of effective transmission access remedies could hinder further development of competitive markets.

The fine-tuning of PURPA avoided cost and QF eligibility requirements might reduce avoided cost payments and the amount of available QF power in States such as California, Texas, and Colorado where high avoided cost rates or high QF capacity potential have provided an initial abundance of QFs seeking contracts with local utilities.

Scenario 2

Scenario 2 would expand QF eligibility criteria under PURPA and provide greater access to wheeling services for wholesale and retail customers. This scenario could have significant local impacts. On the one hand, scenario 2 could expand the current abundance of QF power in some regions. On the other hand, the influx of additional QF power could drive QF avoided cost payments down, providing some financial relief to host utilities and their ratepayers. (This would be of only limited value if high cost QF capacity is already under long- term, fixed-price contracts.) Availability of wheeling could allow QFs, independent power producers (IPPs), and utilities greater access to potential customers for their power and could reduce the purchase obligations of some host utilities. The wheeling of QF power from the host utility's service area to utilities with higher avoided cost payments, who must then purchase the offered power, is an option under existing law, but there is no mandatory transmission access under PURPA.

The scenario could favor large fossil-fueled QFs and IPPs that enjoy some economies of scale and discourage the smaller alternative generating technologies originally targeted in PURPA, unless the smaller facilities could match competitive prices. It could also result in different local environmental impacts than would arise from the plant mix under the existing system.[49]

Scenario 2 would require Federal legislation and complementary changes in State regulatory systems. If States were given authority over retail wheeling requests, States could make the public interest determinations associated with problems of bypass and interclass allocations of system costs in the ratebase. The availability of retail wheeling would mean that utility systems with higher retail prices than other systems in their regions could see increased vulnerability to bypass, and loss of customer load and revenues.[50] Under scenario 2 bypass could be exacerbated not only among retail customers, but also, more significantly, among wholesale requirements customers.

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[46] "A Real Massachusetts Miracle," *Public Utilities Fortnightly*, vol. 121, No. 15, July 21, 1988, pp. 6-7; Massachusetts Department of Public Utilities. "Pricing and Rate-making Treatment to Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities," D.P.U. 86-36-C, May 12, 1988.

[47] State Government Survey Responses, supra note 45.

[48] Ibid.

[49] The FERC draft EIS assumes that expanded participation of IPPs will displace QF capacity (coal, oil, gas, and waste). See DEIS ch. 4, supra note 42. See also the discussion in ch. 7 of this report.

The additional transmission incentives under scenario 2 could include more explicit consideration of State and regional transmission needs in energy planning and ratemaking decisions. State or regional entities might offer to mediate arrangements for compensation and/or mitigation with affected property owners and localities, for example, to assist in resolving conflicts that might hamper needed transmission facilities. Regulators would be more involved in oversight of transmission. Federal and State regulators might encourage a greater willingness for voluntary provision of transmission services through experiments in pricing wheeling transactions and incentives for expansion of transmission capability.

If transmission prices and interconnection conditions are not so onerous as to render transmission access provisions ineffective, the stresses on already heavily loaded transmission systems will increase and create even more pressure for additional capacity. If scenario 2 results in a large net increase in system demands, areas in ECAR, MAAC, NPCC, ERCOT, and WSCC are likely to see the most serious effects. Scenario 2 could result in utilities being ordered by States or FERC to construct additional transmission capacity to provide wheeling services. Scenario 2 would not preempt local and State authority over siting approval, however. This result would also occur under scenarios 3, 4, and 5.

Scenario 3

Scenario 3 is similar in some aspects to FERC's competitive bidding NOPR, but requires that all States use competitive bidding and also includes mandatory wheeling authority.[51] The responsibilities and administrative burdens carried by State regulatory agencies would increase markedly under this scenario, most noticeably in States with more modest traditional regulatory programs and in those States with high growth in electricity demand. FERC's administrative caseload would also increase. Under scenario 3, regulatory proceedings would probably involve more parties as competitive power suppliers joined utilities, regulators, and consumers in needs determinations and in the review and awarding of new source contracts.

The participation in all source competitive bidding in areas needing capacity would depend on how the solicitation is structured and the weighting of nonprice considerations. In particular, many traditional QF cogenerators and small power producers could be discouraged from competing in a highly structured bidding program against larger and more sophisticated IPPs and utility affiliates. Similarly, conditions such as wheeling requirements or protections against self-dealing could constrain utility participation both inside and outside their service territories. In its draft Environmental Impact Statement (EIS), FERC projects that its proposed rulemakings on competitive bidding and IPPs might result in significant displacement of incremental utility and QF capacity, including some renewable energy technologies. Additionally, the draft EIS concludes that the locations of new generating plants and transmission loading patterns could be shifted among various regions.[52] It also expresses doubt that real impacts would be felt until the mid to late 1990s at the earliest because of existing capacity abundance. In the limited experiences with competitive solicitations that have taken place, there has been a mix of IPPs, utility affiliates, and cogeneration projects proposed, but it is still too early to determine what would happen if all source competitive bidding were to replace the existing alternatives of utility construction, negotiated purchases, and required QF purchases.[53]

The availability of wheeling might encourage wholesale requirements customers to seek alternative power suppliers, possibly exacerbating the problems of "stranded investment" and bypass on high-cost utility systems. The departure of existing customers could leave the remaining ratepayers with the burden of paying for a system that is larger than required unless regulators shifted a sizable portion of the losses to the utility and its shareholders. Because there is no retail wheeling under scenario 3, its impacts on the transmission system might be less than those of scenario 2, at least initially. More lines might eventually be built in scenario 3 than in scenarios 1 or 2 to support the competitive system and to open up new markets as the industry shifts away from the old model of self-sufficient integrated regional utilities tied together for enhanced reliability.

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[50] Many high-cost utilities already face problems because of conservation, self-generation, and/or plant-closings. Wheeling, and in particular retail wheeling, would give their customers another means of avoiding the high prices of local utilities. This problem would exist under scenario 3, but without the additional strains of retail wheeling.

[51] It has been argued that the effective result of the three FERC NOPRs is to impose all source competitive bidding on States, since compliance with requirements for administrative avoided costs would be unduly burdensome so that regulators and utilities would rely on bidding.

[52] DEIS, supra note 42, ch. 4.

[53] See discussion in ch. 5 on the California, Maine, and Virginia competitive bidding systems and in ch. 7 on the Massachusetts bidding system.

According to some proponents, the expanded competitive market and availability of wheeling could theoretically dampen the discrepancies in the prices of power within and among regions as lower-priced power is bid up and higher-cost/higher-priced producers are forced to cut costs or be displaced. Because electric power would typically be committed under long-term contracts, it is not clear how long this will take and how great the impacts will be on consumers and electric supplies over the period needed for market forces to accomplish this result.

Scenario 3's success will in large part depend on local characteristics. The early impacts and experiences will come in areas that need generating capacity from 1995 through 2000. In some areas, however, the power solicitations might not draw enough competitive interest to rely solely on bidding results to set power prices. Reliance on competitive awards might make some areas heavily dependent on NUG power with potentially greater risks of less flexibility in control of generating resources as discussed in chapter 5. Whether this results in lowered reliability for the power system will depend on the adequacy of alternative protective arrangements to compensate for changes in the resource base and system operations. Utilities could offset at least some increased risk by building or contracting for higher levels of reserves than they would under a traditional cost of service system.

Over the long term (20 to 30 years and more), scenario 3 would move the industry toward a competitive generation sector within a regulated and integrated utility structure. This evolving structure will eventually raise some of the same issues presented by scenario 4 about the preservation of competition as an alternative to traditional cost-of-service regulation/pricing, fairness to ratepayers in treatment of proceeds from use of ratebased facilities and intangible assets in promoting competitive activities, and the long-term bargaining power and viability of regulated transmission and distribution sectors.

Of concern under both scenarios 3 and 4 is that some regions may not initially have enough viable suppliers to sustain a competitive market that could be relied upon to set prices in lieu of regulation. This possibility is created in large part by the existing patterns of regulated utility holdings and franchise territories.[54] This may be a particular problem in regions where very large integrated private utilities and holding company systems occupy strategic and dominant positions in ownership of generation and transmission resources. New entrants could be intimidated in situations where utility control of transmission facilities and the uncertainty of gaining a wheeling order combine to restrict access to potential customers.

Scenario 4

Scenario 4 would create an all competitive generating sector over a moderately short transition period (of 5 to 10 years for example as compared to the evolutionary approach in scenario 3). New segregated generating subsidiaries or spinoffs of existing integrated utility companies would initially control an overwhelming share of generation resources under the new system. All generators would be able to sell power and would be eligible for transmission services. The transmission and distribution segments would consist of the segregated transmission and distribution operations of formerly integrated utilities and wholesale/requirements customers. Transmission and distribution utilities would remain regulated and would retain an obligation to serve. There are a number of major uncertainties in how scenario 4 will be implemented that will strongly influence its outcome. The major regional impacts/uncertainties of scenario 4 focus on the viability of competition and the role of State regulation.

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[54] See Joskow and Schmalensee, supra note 41.

Under scenario 4 there is the possibility that newly independent local generators will use access to transmission to flee existing service territories for more lucrative markets, leaving ratepayers and distribution utilities without adequate supplies and facing substantial rate increases.

The existing regulated industry structure will not provide an initial level playing field for creating a new competitive industry. Existing franchise territories and generating resources as well as the considerable financial strengths of some utilities will create competitive advantages. Other utilities may start at a competitive disadvantage. As a result higher-cost producers that once enjoyed the protection of their government-franchised territories could be driven from business under a market-based system, and there could be a marked trend toward consolidation in the generating sector. Some transmission and distribution utilities would also become candidates for mergers or acquisitions.

Regions and States with extensive existing transmission arrangements through power pools, coordination agreements, and Federal power marketing systems might have an advantage in creating the necessary institutional infrastructure for separate transmission utilities under scenario 4.

If all bulk power supply arrangements fall under exclusive Federal jurisdiction because they are "sales for resale," State and local regulators with jurisdiction over distribution companies face the loss of any effective influence over generators, thus imperiling the adequacy of their regulation of transmission and distribution. New Federal and State policies may be needed to protect the interests of ratepayers and the public under a changed market and regulatory structure.

Scenario 4 has a very high potential for substantial impacts on consumer electric prices in many regions, if the transfer from regulated rate-based assets and service territories to unregulated competitive generators and open markets is not handled equitably. In the transition, utilities could gain windfalls from the sale of low-cost power produced by older, depreciated plants or from the sale of those plants. The profits could be transferred to or retained by their new unregulated generating companies. Policymakers could limit this potential by requiring that rate-based assets from the predecessor integrated utility be transferred at either replacement or market cost with the proceeds going to the successor regulated distribution utility and its ratepayers. Additionally, communities and ratepayers with low retail rates may lose many of the financial benefits of past sound and prudent utility management and regulatory oversight as the owners of newly liberated generating plants rush to sell their power at the highest price.

Scenario 5

Scenario 5 also involves the dramatic revamping of the electric power industry and the transfer of billions of dollars in ratebase assets; it differs from scenario 4 in two respects. First it would involve the actual disintegration and divestiture of utility assets into separate legal and financial entities, while preserving the ongoing viability of integrated operational functions through the creation of new entities and new institutional arrangements. Second, its common carrier transmission entities would provide wheeling services for retail customers.

Scenario 5 shares almost all of the concerns over industry concentration, preservation of competition, and reliability as scenario 4 plus the additional challenges and complications of creating a common-carrier transmission system that will adequately serve the needs of utility and nonutility customers.

To be an effective entity, the common carrier transmission company would likely be involved in multistate operations and would thus create additional challenges to Federal and State regulation and oversight of rates, planning, and siting activities.

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REGIONAL PROFILES[55]

The East Central Area Reliability Region (ECAR)

ECAR
MICHIGAN
PENNSYLVANIA
OHIO
INDIANA
MD
WEST VIRGINIA
KENTUCKY
VIRGINIA

Voting membership in ECAR is open to those members that meet three criteria. They must: own an electric utility system engaged in the generation, transmission, and sale of power in the region; operate in synchronism with two or more members in the Agreement; and have a significant impact on reliability. Nonvoting members are those systems that do not have a significant impact upon reliability but share concerns relating to the reliability of bulk power supply.[56]

Fuel Use

ECAR is heavily reliant on coal and is expected to continue this reliance well into the 1990s. Nuclear is projected to increase slightly its share of total electricity production from 8.7 percent of the total in 1988 to 9.3 percent in 1997.

Capacity

According to NERC, installed capacity will increase by about 7,100 MW by 1997. Only three major unit additions, totaling 3,095 MW, are scheduled during the 1988-1997 period. Very little new capacity is scheduled for operation after summer 1991.

Average annual growth for the period 1988 to 1997 is projected to be 1.6 percent for summer and 1.7 percent for winter. ECAR is expected to be summer peaking throughout the period.

Transmission

ECAR has an extensive system of intrasystem, intraregional, and interregional connections ranging from 115 kV up to 765 kV. According to NERC, current plans for the 1988-97 period call for an additional 100 miles of 500 kV and 200 miles of 345 kV transmission lines.

Transmission networks in the eastern part of the region provide connections with Southeastern and Northeastern areas of the United States. Networks in the western part of the region provide interregional connections with MAIN. These ties result in substantial interregional power transfer capacity. The American Electric Power Company owns about 40 percent of the high-voltage capacity in ECAR.[57]

In recent years, ECAR's extensive transmission network has experienced numerous large-scale economy transfers, which are created by fuel-cost differentials. These intraregional and interregional economy transfers have caused power flow patterns that were not anticipated when the system was planned. To continually ensure transmission system reliability, ECAR and neighboring regions conduct performance evaluations before each summer and winter peak load season and annually.

Bulk Power Transactions

Within ECAR, bulk power transactions to other regions, especially the PJM Interconnection and Virginia, are based on load diversity and fuel cost differences. American Electric Power and Allegheny Power Systems, two large holding companies in the region, dominate sales transactions[58] and control much of the transmission grid. ECAR utilities surveyed by NGA reported the smallest amount of bulk power purchases—3 contracts for 188 MW. On the other hand, ECAR utilities reported contracts to sell about 3,600 MW, second only to SERC in terms of sales. The length of the contracts ranged from 6 months to 3 years.

Coordination

Coordination in this region ranges from tight holding company pools, to less integrated pools, to individual utilities that do little coordination. Generally, the region's holding companies and power pools coordinate very well.[59]

Reliability

According to NERC, the existing and planned electric power supply in the ECAR region will satisfy the region's reliability criteria, if generating equipment continues to be available at present levels and load and capacity conditions are as projected. Even a small decline in generating equipment availability and/or a slight increase in load growth could quickly reduce the future power system reliability to unacceptable levels.

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[55] Regional profiles are based primarily on NERC documents, unless otherwise noted.

[56] "Reliability Council Survey Responses," supra note 2, p. 5.

[57] FERC, *Power Pooling*, December 1981, p. 96.

[58] DOE, *Interutility Bulk Power Transactions - Descriptions, Economics, and Data*. October 1983, p. 41.

[59] FERC, supra note 57, p. 97.

NERC expects capacity margins to decrease over the next decade, from a current level of 23 percent. As capacity margins decrease, generating units will be utilized more intensely. Placing greater demand on these units may be increasingly difficult as plants get older. By 1997, 42 percent of all generating units in this region will be 30 or more years old.

Furthermore, because of its dependence on coal to generate electricity, ECAR is especially vulnerable to acid rain legislation. Strong new pollution control equipment requirements could affect the availability of coal-fired generating capacity in the region, possibly reducing reliability.

Electric Reliability Council of Texas (ERCOT)

Membership in ERCOT is open to any entity that owns, controls, and operates an electric power system in Texas. Members' votes are weighted on the basis of the average number of kWh handled through the intrastate system for the preceding 3 calendar years. Each entity is assured at least one vote.[60]

ERCOT
TEXAS

Fuel Use

ERCOT utilities rely heavily on coal and gas to generate electricity. NERC projects that by 1997 coal will increase its share to 44 percent, and gas use will decrease from a 45 percent share to a 33 percent share. Nuclear will account for about 11 percent of the total.

Capacity

ERCOT is expected to increase its installed capacity by about 12,500 MW between 1988 and 1997. Member utilities indicate an average annual growth rate of 2.4 percent (summer peak) for this period, which is a reduction from the 3.9 percent rate projected in 1987. Winter peak demand is forecast to grow at 3.2 percent for the same period.

Transmission

In recent years, ERCOT has experienced increases in both firm and economy energy transfers. At the same time, transmission additions have not come on line as quickly as anticipated. Moreover, planned additions have been reduced. ERCOT expects to install about 931 miles of 345 kV lines during the next 10 years. This figure represents a 29 percent reduction from the 10-year projections made in 1987. In 1987, ERCOT had 6,871 circuit miles of 230kV and above transmission lines.

Bulk Power Transactions

Because ERCOT utilities are isolated from the Eastern and Western Interconnected Systems, bulk power transactions based on generation diversity are limited. Even so, the average ERCOT utility has about the same volume of transactions as does the average U.S. utility, according to DOE.[61] This may be due, in part, to the wheeling of QF power from large cogenerators in the region. The NGA survey found that ERCOT utilities had contracts to buy 1,760 MW and sell 3,200 MW.

Coordination

The Texas Interconnected System (TIS) is the umbrella coordinating group in ERCOT. Its primary focus is on bulk power supply reliability, through coordinated planning and operation. Bilateral agreements form the core of existing coordination.[62]

Reliability

NERC expects planned capacity resources to be adequate during the 1988-97 period. The projected capacity margins range from 21.3 percent in 1988 to a high of 23.6 percent in 1990 and to a low of 16.4 percent in 1996. These margins exceed the planning guidelines adopted by the region. Nonutility generation will supplement ERCOT's short- and long-term capacity needs.

On the other hand, transmission system reliability is of some concern to ERCOT. Increases in economy and firm interchanges have placed a strain on portions of the system. NERC expects further increases in transmission system usage to continue because of wheeling for utilities and nonutility generators. According to NERC, during 1986 wheeling of firm electric power amounted to 2,148 MW of capacity—5.5 percent of regional peak demand.

Contributing to this situation is the fact that transmission improvements have not proceeded as planned. One major concern is the recent decision of the Austin City

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[60] "Reliability Council Survey Response," supra note 2, p. 6.

[61] DOE, supra note 58, p. 42.

[62] FERC, supra note 57, p. 132.

Council to cancel construction of several 345 kV lines that were originally scheduled for service in 1988. Concern about possible health effects of electric and magnetic fields was one of the reasons given by the Council for canceling construction. In addition, the Texas Public Utility Commission rejected the proposed Salem-Zenith interconnection. The decision is currently being appealed to the courts.

Another reliability issue is the region's reliance on natural gas as a boiler fuel. The long-term availability and price of this fuel will impact reliability in the future, but to a lesser extent than in other areas as Texas is a major gas producer.

Mid-Atlantic Area Council (MAAC)

PENNSYLVANIA
NEW JERSEY
DEL
MD
MD
MAAC

MAAC voting members must meet three criteria. They must be directly interconnected and operated in parallel with one or more MAAC members; their operations must significantly impact the reliability of the bulk electric supply systems of MAAC members; and they must abide by the rules of the Executive Board. Nonvoting members may include any municipal systems, rural electric cooperatives, or small investor-owned utilities that are served by MAAC members and agree to the principles of the MAAC agreement.[63]

Fuel Use

MAAC relies on coal and nuclear-powered generation. By 1997, NERC indicates that coal's share of electricity production will decrease, while nuclear, oil, and hydro use will remain essentially the same.

Capacity

From 1988 to 1997, installed capacity (summer peak) in this region is expected to increase by about 6,730 MW. Included in this total are about 2,860 MW of nonutility generation and other small unit additions. Also during this same period, 830 MW of existing generation will be retired or derated.

Summer peak demand is expected to grow annually by 1.3 percent, while winter peak demand increases by 2.0 percent annually. MAAC has traditionally been summer peaking, but will convert to winter peaking after the turn of the century if the present trend continues.

Transmission

The MAAC transmission network consists of about 6,500 circuit miles. From 1988 to 1997, an additional 110 miles of 500 kV lines and 400 miles of 230 kV lines are planned for the region. According to NERC's 1988 Reliability Assessment, transmission capability is a concern in MAAC. The increasing use of transmission lines has resulted in heavy loadings on critical lines affecting interregional transfer capability.

NERC reliability reviews indicate that the primary transmission constraint in the area is the major west-to-east transmission path. During 1987, the PJM system was loaded to the limit of its west-to-east transfer capability 96.8 percent of the time.[64]

A 1984-85 study by ECAR/MAAC for DOE cited loop flow from the New York Power Pool and New England Power Pool and weaknesses in the MAAC system and eastern ECAR as limiting the potential for the west-to-east transfer of coal-fired power to back out oil-fired generation in the East. However, the study asserted that the existing transmission system already provided about 90 percent of the economic benefits that could be realized if the existing transfer capacity were doubled.[65]

An increase in nuclear capacity in recent years and the declining differential in oil/gas and coal prices have reduced the overall transfer of economy energy from regions west of MAAC, particularly ECAR. But, internal transfers of energy along the west-to-east transmission path have remained high. This is especially true during daily peak load periods. Because transmission flow patterns in this region are very dependent on oil price fluctuations, future changes in flow patterns will be difficult to predict. Relatively high oil prices would tend to increase the need for west-to-east transfers.[66]

Bulk Power Transactions

MAAC utilities report a relatively low volume of transactions, according to DOE. There may be several reasons for this low volume:

1. MAAC's transmission capacity may limit transactions even when generating capacity is available;

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[63] "Reliability Council Survey Responses," supra note 2, p. 6.

[64] OTA contractor report, "Case Studies on Increasing Transmission Access." Casazza, Schultz & Associates, Mar. 18, 1988, Appendix A, p. A-1.

[65] "ECAR-MAAC Interregional Power Transfer," as reported in OTA contractor report, Ohio Public Utilities Commission, supra note 2, p. 302.

[66] OTA contractor report, Casazza, Schultz & Associates, supra note 64, p. A-1.

2. the joint ownership of several large coal and nuclear power plants can complicate the reporting of a utility's share of a transaction; and
3. the existence of a tight power pool with central dispatch in the region may reduce the need for many intraregional bulk power sales among members.[67]

The goal of central dispatch in MAAC is to reduce costs by using the most economically efficient available generation to meet load. Coal plants are used to back out expensive oil generation. These transactions are conducted both within PJM Interconnection and with other regions, especially ECAR.[68] The NGA survey indicates that MAAC contracted to buy about 3,700 MW of power and to sell 1,300 MW.

Coordination

MAAC has one of the most highly integrated power pools in the country. PJM has strong internal interconnections, especially a strong west-to-east transmission system, which transfers power from minemouth plants in western Pennsylvania to load centers in the East, and interregional connections with ECAR, NPCC, and SERC.[69]

PJM operates under a formal agreement that provides for the coordination of planning and operation, reserve sharing, and rates. Coordination in MAAC is handled well and may be better than any other region in the country, according to FERC.[70]

Reliability

A number of factors may affect MAAC's future reliability. These include a higher than projected load growth, inadequate performance of load management programs, delays in generation additions, limited transmission import capability, and decreased availability of existing generators.

The most critical of these factors, according to NERC, is a higher than projected load growth. Peak load growth is forecast at 1.3 percent annually for the 1988-1997 period.

Capacity margins are forecast to range from about 19 percent in 1988 to 20.3 percent in 1997. MAAC expects these margins to provide sufficient generating capacity over the next decade. However, if load growth increases beyond projections, margins may be inadequate by the mid 1990s, even if all planned capacity is installed on schedule.

Another potential adverse impact on reliability involves increases in loading on MAAC's transmission system. Heavy power flows can also increase loading on other utilities' systems not party to the transactions, as well as decrease reliability and limit economic benefits from internal energy transfers. NYPP's importation of hydropower from Canada has affected MAAC's transmission system. To counteract this, the New York Power Pool (NPCC) and PJM have agreed on what constitutes normal and excessive use of each others' transmission system. The agreement includes an arrangement to purchase and install phase shifters in 1988. Phase shifters change the way power flow divides along different paths—decreasing flows that are too high and increasing those that can safely be increased. (See box 6-A on OTA's transmission case study—"Importing Power From Canada to New England.")

Still another potential source of adverse impact is disturbances caused by sudden loss of generation in regions outside MAAC. A loss of generating sources to the north and east of the MAAC region will cause a significant increase in power flows from the west to the east—ECAR to MAAC. This west-to-east power flow could adversely affect the reliability of the MAAC system. According to NERC, MAAC and neighboring regions participate in coordinated planning and operation to ensure that adequate reliability is maintained.

Because of its reliance on coal-fired power plants, MAAC may be affected if stringent new pollution control requirements are adopted as part of acid rain legislation. Compliance could require that some older plants be retired and that output be reduced at other plants. If plant availability is reduced, regional reliability levels could be affected. The potential for power purchases by MAAC utilities from coal plants in ECAR could also be limited by constraints on capacity availability in that region.

Finally, in the late 1990s MAAC will increasingly depend on nonutility generation additions to offset capacity shortfalls. NERC has estimated that over the next 10 years about 2,860 MW of cogenerated power will be installed, bringing the total to 3,126 MW by 1997.

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[67] DOE, supra note 58, p. 43.

[68] Ibid.

[69] FERC, supra note 57, p. 72.

[70] Ibid., p. 78.

Box 6-A—Transmission Case Study: Importing Power From Canada[1]

To meet rapidly growing load as well as displace expensive oil-fired generation, New England utilities are pursuing a variety of new supply options. One seemingly attractive option is to import power from neighboring Hydro-Quebec, a Canadian utility. Unexpected low load growth combined with excellent hydroelectric facilities give Hydro-Quebec a large surplus of low-cost power. However, the transmission systems of Quebec and New England are not synchronized and can only be linked by high-voltage direct current (HVDC) ties. At present, the Hydro-Quebec system is connected to the Eastern Interconnection through five HVDC ties with a capacity of 2,590 MW. A power purchase agreement called the Phase I Project was developed to make full use of the existing facilities.

Phase I Project

The Phase I Project consists of a formal agreement for the sale and transmission by Hydro-Quebec to NEPOOL of 33 million MWh of surplus hydroelectric power over an 11-year period, beginning in 1986. This energy purchase agreement does not guarantee that NEPOOL will obtain any specified amount of power at the time of its critical needs. However, NEPOOL does treat this agreement as reliable enough to justify not building 600 MW of capacity.[2]

At present, imports are constrained by 1) limited capacity of existing AC-DC converters at two locations—Des Cantons and Comerford; 2) limitations in the AC systems in New England; and 3) lack of agreement to transfer more power. An expansion of transmission facilities, called the Phase II Project, has been proposed to eliminate these bottlenecks.

Phase II Project

The Phase II proposal calls for a total additional firm energy purchase of 70 million MWh over a 10-year period, beginning in 1990, and for the building of necessary transmission facilities for its delivery. In general, NEPOOL will be entitled to schedule deliveries in any hour up to the 2,000 MW capacity of the tie. There are limitations on the rate of change of deliveries from one hour to the next, and Hydro-Quebec may interrupt deliveries during limited periods of time. NEPOOL considers the Phase II agreement a reliable source of 900 MW. Thus, the combined Phase I and II will replace 1,500 MW of additional installed capacity in New England.[3]

Transmission limitations will be resolved by adding both HVDC and AC components. In Canada, the HVDC components consist of a new 700-mile HVDC line and an AC-DC convertor rated at 2,000 MW. In the United States, the Comerford-Sandy Pond line will be extended by 133 miles. The NEPOOL AC system also has to be expanded to absorb the additional Phase II power and distribute it to various load centers in New England. The AC expansion consists of constructing two new 345 kV AC transmission lines, totaling 51.8 miles, along existing transmission rights-of-way. In addition, substantial substation reinforcements are required.

While these new facilities would allow increased transfers without overloading the New England and Hydro-Quebec systems, the project could create increased costs and transmission constraints in neighboring regions. These effects underline the importance of considering the impacts of one region's changes on other regions.

Interregional Impacts

Increased imports as well as reliability concerns have an impact on the operation of other regional systems. Because NEPOOL, NYPP, PJM, ECAR, and other systems that make up the Eastern Interconnection are all interconnected and operate synchronously, serious disturbances could be propagated from one of the systems to its neighbors and even to more distant systems. This is particularly important given the large size of the Canadian transfers. The loss of the Phase II transmission system would result in a disturbance much worse than the loss of the largest generator in the Northeast.

When the power supply in New England is suddenly reduced by 2,000 MW, the maximum that can be lost due to any contingency, this loss is immediately replaced by power generated in New England and in all the areas connected with New England, from the Rocky Mountains and the Gulf Coast to Nova Scotia. Most of this power is generated in areas to the west of New York and PJM, and passes through these on the way to New England.

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[1] This material is drawn from an OTA contractor report, Casazza, Schultz & Associates, Inc., "Case Studies of Transmission Bottlenecks," Nov. 30, 1988.

[2] "New England/Hydro-Quebec 405 kV Transmission Line Interconnection—Phase II," Final Environmental Impact Statement, Economic Regulatory Administration, Office of Fuel Programs, DOE, August 1987.

[3] New England Hydro-Transmission Electric Co., "Amendment to Supplement 2C to Long-Range Forecast 2 for the Ten-Year Period 1984-1993," submitted to the Massachusetts Energy Facilities Siting Council, November 1984, vol. 1, p. 4.

These large power flows are added to the predominantly eastward economic power flows in the PJM and NYPP areas from ECAR and other midwestern areas. The very large combination of the eastward power flows through PJM and NYPP can cause thermal overloads, inadequate voltages, and possible instability on heavily loaded circuits.

The MEN Study Committee, a group representing PJM, ECAR, and NPCC, found that Phase II imports of less than 1,500 MW do not require PJM or NYPP to restrict their power transfers more severely than they must for contingencies in their own system. Larger imports, up to 2,000 MW, would affect PJM restrictions but not those of NYPP, according to the MEN Study. PJM would have to restrict its imports from ECAR more severely—to 3,250 MW or less—than if it were responding to a contingency in its own system, or risk severe voltage problems if NEPOOL lost its Phase II imports. Therefore, Phase II imports may not be increased to 2,000 MW unless PJM is importing 3,250 MW or less from ECAR.

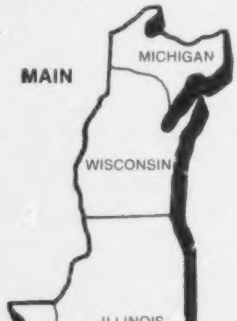
An alternative to restricting imports would be to install additional transmission facilities on either the PJM or NYPP systems. Technical details and costs of such changes have not been determined, and the allocation of any costs would have to be negotiated among the parties involved.

Economic Consequences

Some consideration has been given to what transmission reinforcements would be necessary to remove existing limitations on the ECAR-to-PJM and NYPP transfers. The exact nature of these reinforcements, their cost, and the amount by which these limitations would be relieved are not available because studies have been, for the most part, informal and preliminary. The informal general consensus among system planners in the region seems to be that the cost of increasing transfer capabilities by substantial amounts is likely to exceed the economic gain produced by these increases, at the present cost differentials.

The Phase II power imports agreement is estimated to produce capacity and energy cost benefits with a present worth of $1,849 million at an estimated cost of $948 million. These benefits will be reduced somewhat by the need to limit the total imports to less than full capacity of the HVDC ties, whenever increasing imports would threaten the reliability of systems in New York or Mid-Atlantic areas.

Mid-American Interconnected Network (MAIN)



Voting membership is open to all but one of the original signers of the MAIN agreement and to any other power supplier that has a 115 kV or higher interconnection with a regular member, whose operations have a significant impact upon reliability, and who undertakes the obligations of the MAIN Agreement.[71]

Fuel Use

MAIN relies heavily on coal and nuclear power to generate electricity. By 1997, NERC predicts coal's share will increase slightly and nuclear's share will decline.

Capacity

NERC anticipates installed capacity to decline slightly over the next 10 years. The recent addition of 4,310 MW should be adequate to maintain reliability through 1997. No major additional units are planned during the 1988-1997 period.

Annual summer and winter peak demand are projected to increase 1.6 and 1.9 percent respectively during this period.

Transmission

NERC indicates that the region's transmission system is adequate for reliable operation of both internal and interregional transfers. Interconnections to the east and southeast provide substantial capability for interregional transfers from MAIN to other regions. Several new lines are scheduled for service within the next few years.

To assure adequacy, MAIN conducts studies on a regular basis. Also, MAIN participates in two interregional reliability coordination agreements. One includes MAIN, ECAR, and the Tennessee Valley Authority (TVA) subregion of SERC. The other includes MAIN, MAPP, and SPP.

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[71] "Reliability Council Survey Responses," supra note 2, p. 7.

Bulk Power Transactions

According to DOE, MAIN has a low volume of reported transactions. One reason may be that the largest utility in the region—Commonwealth Edison—uses most of its coal and nuclear capacity in its own heavily loaded service territory. Also, the lack of established transmission access agreements may limit large-scale purchases and sales.[72]

Those utilities that have abundant coal capacity sell to or interchange power with those that are dependent on oil and gas or need additional capacity to meet load.[73] The NGA survey respondents contracted to buy only 213 MW and to sell 585 MW.

Coordination

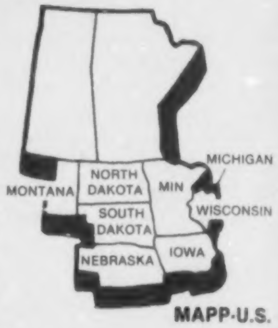
Individual bilateral agreements appear to form the core of coordination within this region. For example, coordination between MAIN and MAPP is established through a bilateral agreement. Interregional coordination with several other contiguous regions is pursued through bilateral agreements. FERC has indicated that expansion of a power pool or coordinating group within the region, rather than dependence on individual bilateral agreements, could improve coordination which in turn could improve bulk power supply economy.[74]

Reliability

A couple of factors may affect the region's reliability in the future. They are acid rain regulations and a higher than projected peak demand. Because coal is the predominant boiler fuel in the region, new regulations to further reduce sulfur dioxide and nitrogen oxides emissions may affect generation. Older units may have to be retired while others would be retrofitted with emissions control equipment. The cost and lead times to retrofit and/or replace capacity could prove significant and may affect reliability by cutting plant availability.

NERC projects a capacity margin of 15.2 percent for 1997. If loads grow faster than anticipated, additional capacity will be required by the mid 1990s. According to NERC, MAIN utilities may encounter difficulties in adding new generation and capacity in a timely manner.

Mid-Continent Area Power Pool (MAPP-U.S.)



MAPP operates as a formal power pool. Its voting members are electric utilities that own/lease and operate one or more generating units to meet all or part of the system load; are directly interconnected with one or more participants in order to meet obligations of the MAPP Agreement; operate or participate in a 24-hour dispatch center with a terminal on the MAPP communication network; and maintain Accredited Capability[75] during each month.[76]

Fuel Use

MAPP relies heavily on coal and nuclear power for electricity generation. Coal use, which now accounts for little more than two-thirds of electricity generated, is expected to increase to 70.8 percent by 1997. Nuclear's share is expected to decline to 17.5 percent, and hydro's share will decline slightly.

Capacity

Between 1988 and 1997 installed capacity is projected to increase by only 740 MW. This increase consists primarily of a 400 MW coal-fired unit and the return of retired units to service.

Summer peak demand is expected to grow by 1.5 percent annually and winter peak by 1.6 percent annually for the forecast period. MAPP utilities are actively pursuing various load management programs to reduce growth in peak demands.

Transmission

MAAP has experienced increased internal and interregional use of its transmission systems for economy and emergency energy transfers. For example, NERC reported that in 1986 transfer capacity between MAPP-U.S. and MAPP-Canada was utilized at 71 percent of maximum capacity; interregional energy transfer capacity between MAPP and WSCC was almost 87 percent.

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[72] DOE, supra note 58, p. 43.

[73] Ibid.

[74] FERC, supra note 57, p. 109.

[75] Net generating capability plus purchased power excluding economy energy, minus commitments.

[76] "Reliability Council Survey Responses," supra note 2, p. 8.

Furthermore, interregional transfers from MAPP to MAIN and SPP have been increasing annually since 1976 and are expected to continue over the next decade. According to NERC, improvements currently underway or planned should help alleviate concerns. NERC expects the region's transmission facilities to be adequate through 1997.

Bulk Power Transactions

MAPP utilities take advantage of their significant coal-fired capacity by selling to utilities in other regions. Bulk power transactions within the region are based on least-cost generation. But, the region's lack of generation diversity may limit the potential for large-scale purchases and sales.[77] The NGA survey indicated that MAPP respondents contracted to sell 1,900 MW and to purchase 2,470 MW.

Coordination

MAPP consists of the Upper Mississippi Valley Power Pool, the Iowa Power Pool, and the Nebraska Public Power Systems. Pool agreement provisions cover capacity and transmission plans and requirements and daily and seasonal operations. However, the pool agreement does not oblige members to provide bulk power supplies to other members over a long period of time. Individual utilities would have to independently arrange for their power needs.[78]

Reliability

Capacity margins for summer peak periods in MAPP are projected to decrease from 27.6 percent in 1988 to 21.4 percent in 1997. Although capacity margins will decrease during this period, NERC expects that they will meet reliability criteria and should therefore be adequate.

Some of MAPP's coal-fired generation could be affected by additional pollution equipment requirements to control acid rain precursors. The available power from these units could be reduced, which in turn, would have a negative impact on the region's reliability. But, the impacts in this region are expected to be much less than in ECAR and MAIN.

Northeast Power Coordinating Council (NPCC)

VT NH
ME
MASS
RI
NEW YORK
CONN

NPCC-U.S.

NPCC includes members in the United States and Canada. Member systems in New England form the New England Power Pool (NEPOOL), and member systems in New York form the New York Power Pool (NYPP). Membership is available to electric systems which have a substantial effect on the service reliability of the Northeast interconnection.[79] The discussion in this section refers to the U.S. portion of NPCC unless otherwise noted.

Fuel Use

NPCC member utilities rely most heavily on nuclear and oil, followed by coal and hydro to produce electricity. NERC projections for 1997 show that nuclear's share is expected to increase; oil and coal use will decrease.

Capacity

NPCC installed capacity is projected to grow at an annual rate of 1.2 percent from 1988 to 1997. During this same period, annual summer and winter peak demand are expected to grow at 1.9 percent and 1.3 percent respectively. NERC projects that about 6,000 MW of new capacity will be added by 1997. The only major utility-owned capacity addition scheduled for service in New England over the next decade is the Seabrook I nuclear plant. The Ocean States Power Project, an independent power project which is owned jointly by several utilities and a Canadian gas pipeline company, also is expected to contribute 470 MW of capacity.

Transmission

NPCC transmission systems have experienced dramatic increases in power flows over the last 10 years. The increases have been due to fuel price differentials, the need to locate generating resources farther from urban load centers, and the growing reliance of NPCC systems on generating resources in Quebec. NERC expects heavy flows to continue in the future. Construction of several new transmission lines from HydroQuebec and upstate New York to load centers in southeastern New York and New England will provide additional sources of generation and improve reliability. These imports will require the continued use of special protection and control systems to maintain transmission reliability in NPCC and adjacent regions.

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[77] DOE, supra note 58, p. 44.

[78] FERC, supra note 57, p. 110.

[79] "Reliability Council Survey Responses," supra note 2, p. 9.

Bulk Power Transactions

According to DOE, most of the bulk power transactions in this region are based on reducing costs at the margin by taking advantage of load diversity and operating differences. The biggest purchasers of electricity, according to DOE, are the utilities that have coal-fired capacity. These utilities also tend to be the largest utilities with the heaviest loads.[80]

Determining NPCC's volume of bulk power transactions is difficult for a couple of reasons. One reason is the different methods of reporting within NPCC. (NYPP utilities report their pool transactions as purchases and sales, while NEPOOL reports their transactions as interchanges.) Another reason is that joint ownership of power plants in the region tends to complicate reporting of purchases and sales.[81]

The NGA survey indicated that NPCC utility respondents engaged in a relatively low volume of bulk power transactions, compared to other regions. Utility respondents contracted to sell about 1,091 MW of power and to buy 2,356 MW. Like MAAC, the existence of the two tight pools in NPCC may obviate the need for a lot of intraregional transactions among members.

Coordination

NEPOOL and NYPP are two of the most integrated power pools in the country. Both have strong interconnections that provide for substantial interpool and interregional transfer capability including imports from Canada.[82]

Both pools operate under formal agreements that provide for joint organization, planning, and operation. Because NEPOOL's membership is more diverse, its agreement is more complex and comprehensive than NYPP's.[83] In addition to the pool agreements, the utilities are tied together through dozens of bilateral agreements.

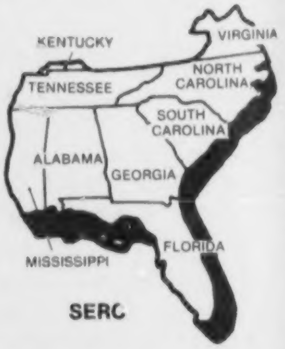
Reliability

According to NERC, supply adequacy will depend on the installation of both utility and nonutility generation, the success of demand management and life extension programs, and large-scale power transfers. In NPCC, supply adequacy is also very dependent on demand not exceeding projected growth rates for the 1988-1997 period.

NERC indicates that projected capacity resources in New York are adequate to meet forecast demand through the next 10 years. This projection assumes that generation additions, including the Shoreham nuclear unit, are realized and demand management and life extension programs are successful. For NEPOOL, NERC estimates capacity should be adequate through 1992/1993. Beginning in 1993, NEPOOL's resources are expected to fall below NPCC's reliability criteria. NERC's current projection for this region differs from that reported in its 1987 reliability assessment, which expected capacity resources to be adequate through 1996.

Oil-fired units represent about half of total New York and New England generating capacity. This heavy dependence on oil and the future availability of adequate oil supplies are major reliability concerns to NPCC utilities. The availability of the region's nuclear capacity is also important. Boston Edison's Pilgrim nuclear unit has been shut down by the Nuclear Regulatory Commission (NRC) because of safety considerations. The NRC has given approval to restart the unit, but the Commonwealth of Massachusetts is opposing that decision based on its concerns over the feasibility of developing adequate emergency evacuation procedures.

Southeastern Electric Reliability Council (SERC)



Voting membership in SERC is open to any power supply entity operating or responsible for operating facilities connected to the interconnected power system, which is located in the SERC membership area and which provides bulk power supply with a normally connected generating capacity of 25 MW or more. Non-voting membership is open to four representatives on a sub-regional basis for each of two categories: 1) municipal or other publicly-owned systems; and 2) rural electric cooperatives.[84]

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[80] DOE, supra note 58, p. 44.

[81] Ibid, p. 45.

[82] FERC, supra note 57, p. 73.

[83] Ibid, p. 74.

Fuel Use

SERC members rely on coal and nuclear power, and to a much lesser extent on hydropower, to produce electricity. In 1988, NERC expects coal to account for almost 60 percent of electric power production, and nuclear about one-fourth. By 1997, NERC projects that coal's share will decrease slightly and nuclear will increase.

Capacity

The SERC region will experience the largest growth in installed capacity. NERC expects that about 17,236 MW of new capacity will be added between 1988 and 1997. In addition, about 6,200 MW of nonutility generation are projected for this period. Based on these projections, the annual growth rate will be 1.8 percent through 1997. At the same time, both winter and summer peak demand growth are projected to increase by 2.4 percent annually.

Transmission

The existing SERC transmission system includes about 27,000 miles of 230 kV+ powerlines. SERC is interconnected with transmission systems in four other regions: SPP, MAIN, ECAR, and MAAC. During the 1988 to 1997 period, over 600 miles of 500 kV and 1,700 miles of 230 kV lines are expected to be added. Included in SERC's plans are two major 500 kV interconnections between SERC and SPP and one major 500 kV transmission interconnection between SERC and ECAR.

NERC expects that existing and planned facilities will provide adequate energy transfer capability between SERC and other regions, and among SERC subregions. Certain portions of the system, however, are experiencing and will continue to experience heavy use. Because of this, several key tie lines between utilities, subregions, and regions are closely monitored. These include the TVA- MAIN Interface near Paducah, Kentucky; Southern-VACAR Interface near the Savannah River; TVA-SPP Interface near Memphis, Tennessee; and the Southern Co.-Florida Interface.

Bulk Power Transactions

SERC has abundant and diverse generating capacity. The availability of coal-fired and hydro capacity, especially in the Southern Company service area, and the Carolinas, affects the volume and type of bulk power transaction within the region. Transactions are also influenced by the amount of oil capacity in Florida and Virginia. For example, Florida and Virginia utilities buy coal-generated electricity from Southern utilities to back out oil capacity. Most of these transactions are used to obtain marginal cost reductions by exploiting load diversity.[85]

Also, there are substantial transactions between SERC and ECAR that involve the sale of coal-generated power to utilities that depend on oil capacity.[86] According to the NGA survey, SERC accounted for the largest volume of bulk power transactions in both sales and purchases. SERC has contracts to buy more than 12,750 MW. Sales contracts total over 7,480 MW.

Coordination

SERC is divided into four subregions: TVA, Southern, VACAR, and Florida. Strong interconnections exist in a north-south direction between TVA and Southern Companies and in an east-west direction between Southern and VACAR. Interconnections between TVA and VACAR are limited.[87]

Coordination among the four subregions is achieved primarily through bilateral agreements. Southern Co. affiliates are tied together in the holding company pool. The Florida utilities participate in an energy broker system, which provides some of the benefits of a formal pool arrangement. VACAR and TVA use bilateral interchange agreements to coordinate bulk power transactions.[88]

Reliability

NERC expects that generating capacity margins in this region should be adequate during the 1988-1997 period, provided capacity additions and peak demand are as projected. NERC also expects that SERC transmission systems will provide adequate emergency transfer capacity between SERC and other regions and among subregions.

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[84] "Reliability Council Survey Responses," supra note 2, p. 9.

[85] DOE, supra note 58, p. 45.

[86] Ibid.

[87] FERC, supra note 57, p. 83.

[88] Ibid, p. 85.

Southwest Power Pool (SPP)

SPP

KANSAS
MISSOURI
OKLAHOMA
ARKANSAS
TEXAS
MISS
LOUISIANA
NEW MEXICO

Voting membership in SPP is open to any system that: is interconnected at 115 kV or above with any SPP member; owns and controls a 115 kV or higher transmission line in synchronous operation and with an installed total capability of 100 MW or greater; owns or controls not less than 300 MW of installed generating capacity with the SPP area; makes a significant contribution to overall reliability in SPP; generates on a 24-hour basis; and has a 24-hour dispatch center or has contractual arrangements with a load control area to fulfill that function. Nonvoting membership is open to utilities which serve 25 MW of load and control not less than 25 MW of operable generation in synchronous operation of a transmission interconnection with an SPP member.[89]

Fuel Use

SPP members rely heavily on coal and to a lesser extent on gas and nuclear power to produce electricity. Over the 1988-1997 period, the fuel mix will remain fairly constant.

Capacity

Between 1988 and 1997, NERC expects that installed capacity will increase slightly by 2,538 MW, which translates into an annual growth rate of 0.4 percent. Summer peak demand is expected to grow 1.9 percent annually, and winter peak demand to grow 2.2 percent annually.

Transmission

The SPP region has an extensive transmission network that includes three direct interconnections from SPP to other regions. In the next decade, SPP plans to install about 1,500 miles of transmission lines, 230 kV and above. Also, two additional interregional circuits are planned to include an interconnection with SERC (TVA) and another dc interconnection with ERCOT.

Interties to the east and northeast provide substantial interregional transfer capability between SPP and SERC and between SPP and MAIN. Interregional transfer capability also exists between SPP and MAPP, but on a smaller scale. Interconnections between SPP and ERCOT are limited because the Texas system is not synchronized with the Eastern system. Similarly, the lack of ties between SPP and the Western United States precludes significant direct emergency power transfer.[90]

According to NERC, SPP's transmission system and interconnections with other regions are adequate and no lines present significant bottlenecks to economy or emergency energy transfers for the 1988-1997 period.

Bulk Power Transfers

Each of SPP's three distinct regional groups—Middle South Group, the Missouri-Kansas Power Pool (MOKAN), and the Oklahoma Group—relies on a different generating capacity mix. Because of these differences in generating capacity, each group engages in different types of bulk power transactions. For example, Middle South engages in substantial purchases and sales and to a lesser extent interchange; MOKAN emphasizes interchange transactions; and the Oklahoma group has more sales than interchanges.[91]

Generally, the utilities that depend on natural gas generation use bulk power transactions to reduce marginal costs, while utilities with coal-fired capacity are either using the transfers to meet native loads or selling coal-generated power to other utilities with oil and gas capacity.[92]

Coordination

Planning and operating coordination is accomplished primarily through the three regional groups. Multiparty pooling, coordination agreements, and bilateral agreements form the core of coordination within SPP.[93]

Middle South Utilities (MSU) is fully interconnected and coordinated. It operates under a formal agreement to which all operating companies and the service company are signatories. MOKAN members individually dispatch their own generating resources. While MOKAN does not practice central dispatch, the systems have arrangements for the economy energy exchanges. Many MOKAN members participate in one or more joint agreements to build transmission facilities in the area.[94]

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[89] "Reliability Council Survey Responses," supra note 2, pp. 9-10.

[90] FERC, supra note 57, p. 121.

[91] DOE, supra note 58, p. 47.

[92] Ibid.

[93] FERC, supra note 57, p. 119.

[94] Ibid, p. 124.

Reliability

SPP anticipates adequate generating capacity margins during the forecast period. The primary reliability concern, according to NERC, is transmission access.

Western Systems Coordinating Council (WSCC)

Membership in WSCC is open to any electric utility or group of utilities in the region regardless of the type of facilities or system size. Voting membership is available to entities with generation in excess of 100 MW or transmission above 230 kV. The Council consists of one representative per member system.[95]

WSCC
WASHINGTON
MONTANA
SOUTH DAKOTA
OREGON
IDAHO
WYOMING
NEVADA
UTAH
COLORADO
CALIFORNIA
NEW MEXICO
ARIZONA
TEXAS

Fuel Use

WSCC members are divided into four separate subregions: the Northwest Power Pool, the Rocky Mountain Power Area, the Arizona-New Mexico Power Area, and the California-Southern Nevada Power Area. Fuel use in each of these subregions is very different. For example, the utilities in the Northwest Power Pool, which is winter peaking, rely primarily on hydropower; the Rocky Mountain Power Area, which is either winter or summer peaking, relies on coal and hydro; the Arizona-New Mexico Power Area, which is summer peaking, relies on coal- and gas/oil- fired generation; and the California-Southern Nevada Power Area, which is summer peaking, is heavily dependent on gas- and oil-fired generation.

Capacity

Net generation additions of 16,771 MW are projected by 1997. The projected additions are considerably less that the net additions placed in service during the past 10 years, however. This reduction is in response to recent lower load growth projections and to the availability and abundance of capacity resources in WSCC.

The annual growth for 1988-1997 is 1.6 percent. During the same period, summer peak demand is expected to grow 1.9 percent annually, and winter peak, 1.7 percent annually.

Transmission

WSCC's overall bulk power transmission network links the principal population centers with major north-south lines along the Pacific Coast and through the intermountain plateau. East-West lines tie the system together. The result is an irregular large loop configuration, often called the "doughnut," rather than an interlocking system that is found in the East. Few transmission lines cross the sparsely populated "hole" of the doughnut in Nevada.

According to NERC, WSCC transmission systems are adequate to accommodate anticipated firm and most economy energy transfer schedules during the 1988-1997 period. Of continuing concern is the effect of heavy economy transfers on bulk electric power system reliability. Because of the region's load diversity and capacity resource mix, plus surpluses of base-load capacity and large fuel price differentials, economy energy transfers between areas are likely to continue.

WSCC members are currently making improvements in the system in order to maintain an acceptable level of reliability. These include upgrading and increasing transfer capability, and completion of additional lines. During 1987, a portion of the new AC Pacific Intertie was placed in service to improve reliability. And, several utilities are planning to install phase shifters on lines connecting Utah/Colorado and Arizona/New Mexico. The phase shifters are scheduled for operation during 1989-1991 and are expected to mitigate the Region's loop-flow problems.

Bulk Power Transactions

There is a heavy volume of bulk power transfers in the WSCC region. Utilities with coal-fired capacity in Utah, Wyoming, Arizona, and New Mexico sell power to California to back out oil and gas. Coal-fired electric power is also sold to the Northwest to supplement hydropower during dry spells and during winter peak periods. The Pacific Northwest sells hydropower to California utilities and other Southwestern States when water conditions permit and during summer peak periods.[96]

Coordination

Coordination and pooling have evolved on a subregional basis among utilities with similar needs and problems. No pool formally plans bulk power facilities as a single integrated system to serve the combined load growth of its members.[97]

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[95] "Reliability Council Survey Responses," supra note 2, p. 10.

[96] DOE, supra note 58, p. 47.

The Arizona-New Mexico Power Area participates in a number of coordination arrangements, which in many cases relate to specific projects and conditions. The Rocky Mountain Power Area and the California-Southern Nevada Power Area rely on bilateral coordination arrangements. And, the Northwest Power Area utilities adhere to the Pacific Northwest Coordination Agreement, which provides for the coordination of resources and establishes rights, obligations, and procedures for all signatories.[98]

According to FERC, power pooling could be especially effective in the Rocky Mountain and Arizona-New Mexico power areas. In the Northwest Power Area, substantial bulk power supply economies are being realized from the coordinated planning efforts of the area's utilities brought about by passage of the Northwest Power Planning Act of 1980.[99]

Reliability

NERC projects that generating capacity margins will range from 33 percent to 26 percent over the next 10 years and will adequately meet demand.

Alaska

Fuel Use

Fuel use varies by region within Alaska. For example, the Railbelt region (Anchorage-Fairbanks) relies primarily on indigenous natural gas to generate electricity; southeastern Alaska is served primarily by Federal and State hydropower projects; and the widely dispersed villages in the rest of the State obtain electricity from diesel-fueled generators, ranging from 50 KW to 7 MW.[100]

Capacity

Alaska's 1986 installed generating capacity was 2,433 MW, an increase of 5.6 percent over 1985 figures. About two-thirds of the installed capacity was in the utility sector; 25 percent in the industrial sector; and about 6 percent in the military sector. According to the Alaska Power Authority, the military's share may continue to decrease if military facilities continue to contract out power production responsibilities to the private sector.[101]

Because of the State's economic recession, current projections are negative for the short term and around 2 to 3 percent over the next 10 to 15 years. The Railbelt region has the largest concentrated segment of load in the State. In the southeast, three major communities use substantial amounts of power: Juneau (55 MW), Sitka (22 MW), and Kethikan (20 MW). The largest rural towns have loads in the 4- to 5-MW range. Load growth forecasts are low for most areas of the State.[102]

Transmission

Alaska has few interconnected electric utilities. The Railbelt region has the strongest interconnected system in the State while all southeast communities are isolated and lack major interties.

Alaska's transmission network consists of 1,681.5 circuit miles. Almost 80 percent of the network is in the Fairbanks and Anchorage-Cook Inlet areas.[103]

Reliability

Reliability continues to be a major concern in Alaska. In the Railbelt, for example, reserve margins are required to be 30 percent. In the rural areas, communities are essentially on their own for electricity, and utilities typically provide high reserve generation levels. Reserve margins of 100 percent are prudent. According to the Alaska Public Utilities Commission, reliability should improve for many isolated systems over the next 20 to 50 years as many communities become interconnected.[104]

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[97] FERC, supra note 57, p. 137.

[98] Ibid.

[99] Ibid.

[100] Alaska Public Utilities Commission letter to OTA, dated Aug. 30, 1988.

[101] Alaska Power Authority, *Alaska Electric Power Statistics 1960-1986*, November 1987, p. 1.

[102] Alaska Public Utilities Commission letter, supra note 100.

[103] Alaska Power Authority, supra note 101, p. 61.

[104] Alaska Public Utilities Commission letter, supra note 100.

Hawaii

The Hawaiian Electric Company (HECO) provides electricity to Oahu and to three other Hawaiian Islands through its subsidiaries Hawaii Electric Light Company (HELCO) and Maui Electric Company (MECO). The systems cover about 95 percent of the Islands.

Fuel Use

Hawaii is heavily dependent on oil and will continue its reliance well into the future. In 1986, oil-fired capacity provided about 93 percent of total capacity. The remainder is supplemented by purchased cogenerated electricity from sugar processing facilities and from wind power companies. In Maui, cogeneration from sugar processing facilities contributes about 19 percent of the island's electricity requirements.[105] However, power contributions from sugar processors or from other renewable resources are not expected to increase substantially.

Capacity

Hawaii's installed capacity in 1986 was 1,535 MW. HECO reports peak demand is 1,205 MW.[106] System peaks occur in the evening. However, HECO projects that by 1990 peaking will occur during the day.

Transmission

The electric systems on each island are not connected with each other. The lack of transmission capability is the biggest impediment to development of the Islands' indigenous resources. For example, the geothermal reserves on the Big Island are considered extensive enough to fulfill most of the State's power needs, but are located far from the load center in Oahu.

Hawaii has 1,465 miles of transmission lines. Hawaii Light Company, an affiliate of HECO, has begun construction of two lines totalling 50 miles. The cost was estimated to be about $11 million.[107]

Reliability

HECO reports a reserve margin of 22 percent for 1987 and projects an increase to 35 percent by 1990.

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[105] Public Utilities Reports, Inc., *The P.U.R. Analysis of Investor-Owned Electric and Gas Utilities*, 1987 edition, August 1987, pp. 148-149.

[106] Ibid.

[107] Ibid.

Chapter 7

Siting, Environmental, and Health Issues Associated With Increased Competition and Expanded Transmission Access

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Chapter 7

Siting, Environmental, and Health Issues Associated With Increased Competition and Expanded Transmission Access

INTRODUCTION

Increasing competition and opening up the transmission grids raise many public policy issues beyond the technical and institutional feasibility of accommodating these changes. This chapter provides an overview of three of the most significant and potentially contentious of these issues: transmission line siting, environmental impacts, and potential public health effects of power frequency electric and magnetic fields. Because of the clear interconnections with proposed industry changes, Congress asked OTA to include consideration of these issues in its assessment.

Siting

The process of gaining approval for transmission line construction has changed and become more formalized as opportunities have been provided for public involvement and greater scrutiny of potential environmental and social impacts of proposed projects. As the Nation is becoming more and more urbanized, competition for available land to route transmission lines has become more intense and right-of-way costs have increased as higher value lands are taken. It is clear, however, that in order to provide an adequate and reliable power supply new and expanded transmission systems will eventually have to be built whether a competitive future path is taken or not. The challenge for industry and regulators is to create a system that plans for and encourages needed expansion and at the same time accommodates other competing interests while resolving or minimizing conflicts. The siting section of this chapter describes generally how transmission line siting decisions are made by State, local, and Federal agencies and discusses several proposals for improving the siting process.

Environmental Impacts

Decisions over the future structure and composition of the electric power industry in the United States have both direct and indirect environmental impacts. These choices will shape fuel mix, dictate location of impacts, and advance or frustrate the achievement of other environmental and social goals. Transmission line construction, operations, and maintenance also raise direct and indirect impacts on the environment. This section discusses the potential environmental concerns presented in the implementation of OTA's alternative institutional scenarios.

Health Effects

One of the most prominent concerns raised by people living near existing or proposed transmission lines is the potential for adverse health effects from exposure to electric and magnetic fields. Scientists are still investigating whether and to what extent these effects are harmful and long lasting and their possible public health implications.

The health section describes the current state of knowledge on health effects of power frequency fields based on available research. It also discusses some of the policy responses to the implications of these research results.

SITING ELECTRIC TRANSMISSION LINES

Long-distance transmission of electricity has increased significantly in recent years. Transmission capacity in some regions is already strained by high usage. At the same time, the pace of construction of new power lines has fallen. Some analysts point to the many licensing and certification processes required to site new transmission lines as one possible reason for this decrease in new construction.

Gaining approval of specific transmission line projects from State regulatory agencies can be a complicated process, often requiring the filing and review of multiple applications. The involvement of many local governmental agencies, the courts, and Federal and tribal governments further complicates the siting process and can lead to jurisdictional conflicts. The participation of a variety of competing interest groups in the siting process for new transmission lines frequently adds to the time required to complete siting and to the complexity of the process.

Long-range planning efforts by utilities and State agencies tend to focus on power generation issues, leaving long-distance transmission issues understudied. Consequently, decisionmakers are often hampered by inadequate information about transmission needs as they review project applications. Constraints imposed by State utility laws and regulations could also hamper decisionmakers as they review large interstate transmission line proposals. Moreover, the lack of multi-State siting procedures and coordination among Federal and State agencies could further encumber the siting of interstate power lines. However, even without such procedures in place, voluntary cooperation among utilities and State and Federal agencies has resulted in the siting, approval, and construction of multi-State lines. The National Governor's Association Electricity Transmission Task Force survey, conducted in the fall of 1986 (hereafter referred to as the NGA survey), indicated that 73 projects had been approved and 84 requests were pending approval within the previous year. In addition, the survey noted that the majority of projects approved between 1982 and 1987 had been completed.[1]

Proposals to improve the siting process for new transmission lines include developing more information about transmission needs in the long-range planning and application review processes, streamlining and clarifying State regulatory agency review processes, broadening multi-State siting efforts, and increasing public participation. Standardizing and expanding reporting requirements, increasing interagency communication, developing clear and consistent evaluation criteria, and creating new regulatory entities empowered to make final siting decisions could also help achieve these objectives. A number of States have already adopted some of these measures.

This section provides an overview of the transmission line siting process, beginning with the long-range energy planning process through which States and utilities strive to identify future electricity supply requirements. It also explores the impediments to power line construction and discusses the perspectives of interest groups towards transmission facilities. Finally, several proposed options to improve the transmission line siting process are examined.[2]

None of OTA's scenarios, described in chapter 3, affect the process for approving the routing and construction of transmission systems. This process is generally separate from the regulatory decisions concerning certification of need and recovery of transmission system investments through ratemaking.

The Siting Process

Once a need for new power supplies has been identified, specific transmission line projects are designed by utilities, and approval for those projects is sought from State agencies charged with certification and licensing. Project approvals from a variety of local governmental entities are usually required. In addition to these State and local siting requirements, special siting approval for power lines crossing Federal and tribal lands and for multi-State transmission line projects is required.

Capacity Planning

Recognition of the need for new transmission lines usually surfaces through long-range energy planning processes that attempt to predict electricity demand patterns in future years and decades. At least 31 States require electric utilities to file long-range supply and demand plans for their service areas.[3] These utility plans discuss, among other issues, anticipated electricity supply and demand, the need for new power generation or transmission facilities, and anticipated nonutility generation capacity. Long-range energy plans generally reflect a 20-year planning horizon, although shorter range planning frameworks of 10 to 15 years are not uncommon. Moreover, utilities are required to submit planning analyses to support their applications for approval of specific power generation or transmission projects.

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[1] "Transmission Line Certification and Siting Procedures and Energy Planning Processes: Summary of State Government Responses to a Survey By the National Governors' Association Task Force on Electricity Transmission," prepared by staff members of the Public Utilities Commission of the State of Ohio and of the West Virginia Public Service Commission, OTA contractor report, July 1988, p. 4, hereafter "NGA survey."

[2] Much of the information in this section is drawn from an OTA contractor report, James S. Cannon, "The Siting of EHV Electric Transmission Lines," May 1988.

[3] National Governor's Association, Committee on Energy and Environment Task Force on Electricity Transmission, *Moving Power: Flexibility for the Future* (Washington, DC: 1986), "Foreword."

In many cases, utility plans are supplemented by energy planning efforts by State government agencies. A recent survey of State electricity regulatory programs by the NGA identified 18 States where public utility commissions prepared independent electricity plans and 12 States where planning was performed by a State energy office or department.[4] However, only a few States, such as California, New Jersey, and New York, require agencies to solicit public comment during the energy planning process and to publish State energy plans at periodic intervals.

According to the National Association of Regulatory Utility Commissioners (NARUC) and NGA, several factors diminish the effectiveness of energy planning processes. First, many State energy regulatory agencies do not have adequate staff either to scrutinize utility long-range plans or to prepare detailed energy forecasts on their own. Thus, planning reports often receive close review by a State agency only when a specific construction project is proposed, which may be years after the need for the project was first identified.

Second, utilities jointly involved in the development of a transmission line submit separate long-range plans, which discuss only those portions of energy projects directly affecting that utility. Most State-mandated, long-range planning programs do not require utilities to coordinate their projects' planning reports. The task of consolidating the individual plans into a comprehensive picture of a State's electric power system often falls to the limited resources of the State agency to which the plans are submitted.

Third, utilities' long-range plans have traditionally focused on generation needs within a particular service area. Issues related to interutility sales and transmission are not necessarily addressed in detail in long-range plans. Thus, NGA's report noted "determinations of transmission requirements are frequently ancillary or iterative to, rather than integral to the determination of need for new generating capacity."[5] Identification of the overall efficiency or the economic benefits potentially obtainable from expansion of the extra-high-voltage transmission line system and increased interutility sales can easily go unrecognized in the planning process.

State Certification and Licensing

Major transmission line construction projects usually require some sort of State certification and/or licensing. Certification normally comes in the form of the issuance of a "Certificate of Public Convenience and Necessity" (CCN) by a State's public utility commission (PUC). Other State agencies, such as the environmental protection department, may also be involved in the licensing of projects through, for example, their responsibility to issue requisite construction and operating permits. In some States, power project siting boards coordinate State agency responses to transmission line projects as well as serve as decisionmaking entities. (See table 7-1.) A CCN is a prerequisite in many cases for other permits and authorizations, such as the taking by eminent domain of land that is needed for the completion of the project.

Requirements for documentation in support of a CCN application are vague in most States, one of the many sources of uncertainty in the certification process. Applications usually include formal testimony by the utility summarizing the utility's argument for the project. Upon receipt of an application, a case or docket is opened by the PUC, a hearing schedule is established, and potential intervenors are notified. Intervenors frequently include other State agencies and utilities, large power users, and public interest groups. The PUC either accepts or rejects intervenors' applications and the case usually enters a "discovery" phase during which the various parties collect and study information about the project obtained through depositions and other methods of information exchange.

At the conclusion of the "discovery" phase, the PUC staff and the intervenors file their formal testimony, and the utility files a second, or rebuttal, testimony. The case next enters the "hearing" phase during which the witnesses submit to examination and cross examination by attorneys for all parties.

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[4] NGA Survey, supra note 1, p. 14.

[5] NGA, supra note 3, p. 16.

Table 7-1—State Certification and Siting Requirements for High-Voltage Transmission Lines

State	Required certification authority	Required siting authority	Agency with final authority for project approval
Alabama	Not required	Not required	NA
Alaska	Not required	Not required	NA
Arizona	Not required	Not required	NA
Arkansas	PUC	PUC	PUC
California	PUC	PUC	Shared with EC
Colorado	—	—	—
Connecticut	—	—	—
Delaware	Not required	DOT (limited)	NA
District of Columbia	PUC	Not required	NA
Florida	PUC	Siting Board	Siting Board
Georgia	Not required	DNR	NA
Hawaii	DNR	PUC/DNR	—
Idaho	PUC	PUC	PUC
Illinois	ICC	ICC	ICC
Indiana	Not required	Not required	NA
Iowa	Utility Division DOC	Utility Division DOC	Utility Division DOC
Kansas	Corporate Commission	Corporate Commission	Corporate Commission
Kentucky	PSC	PSC	PSC
Louisiana	Not required	Not required	NA
Maine	PUC	LURC/BEP	—
Maryland	PSC	PSC	PSC
Massachusetts	PUC/Siting Council	PUC/Siting Council	PUC/Siting Council
Michigan	Not required	Not required	NA
Minnesota	PUC	EOB	—
Mississippi	PSC	PSC	PSC
Missouri	PSC	PSC	PSC
Montana	BNRC	BNRC	BNRC
Nebraska	PSB	Not required	—
Nevada	PSC	PSC/NCNR/NEC	PSC
New Hampshire	PUC	Site Evaluation Committee	—
New Jersey	BPU	BPU/DOC/DEP	Energy Facility Review Board
New Mexico	PSC	Not required	NA
New York	PSC	PSC	PSC
North Carolina	Not required	Not required	NA
North Dakota	PSC	PSC	PSC
Ohio	Siting Board	Siting Board	Siting Board
Oklahoma	Not required	Not required	NA
Oregon	Siting Council	Siting Council	Siting Council
Pennsylvania	PUC	PUC	PUC
Rhode Island	PUC/Siting Board	PUC/Siting Board	PUC/Siting Board
South Carolina	PSC	PSC	PSC
South Dakota	Not required	Not required	NA
Texas	PUC	PUC	PUC
Utah	PSC	Not required	—
Vermont	PSB	PSB	PSB
Virginia	Corporation Commission	Corporation Commission	Corporation Commission
Washington	Not required	EFSEC (limited)	—
West Virginia	PSC	PSC	—
Wisconsin	PSC	PSC/DNR	PSC
Wyoming	PSC	PSC/DPL/ISC	PSC

KEY: BEP=Board of Environmental Protection
BNRC=Board of Natural Resources and Conservation
BPU=Board of Public Utilities
DEP=Department of Environmental Protection
DNR=Department of Natural Resources
DOC=Department of Commerce
DOT=Department of Transportation
DPL=Department of Public Lands
EC=Energy Commission
EFSEC=Energy Facilities Site Evaluation Council
ICC=Illinois Commerce Commission
ISC=Industrial Siting Council
LURC=Land Use Regulatory Commission
PSB=Public Service Board
PSC=Public Service Commission

SOURCE: Summary of State Government Responses to a survey by the National Governor's Association Task Force on Electricity Transmission (prepared by the staffs of the Public Utilities Commission of the State of Ohio and of the West Virginia Public Service Commission), OTA contractor report, July 1988.

Hearings are frequently held before a hearing examiner appointed by the PUC commissioners, although they are sometimes held in front of the commissioners themselves. Most States also require that public meetings be held to solicit public opinion on the project. In some other States public meetings can be called at the discretion of the public service commission.[6]

In instances where a hearing examiner is utilized, he or she prepares a report and a proposed or recommended decision which is reviewed and upheld, rejected, or modified by the PUC commissioners. If the commissioners hear the case, they prepare both the report and render the final judgment. PUC decisions can be appealed to the State court system.

The NGA survey found that the certification process in most States generally takes less than a year, although the process can take years in some complex or controversial cases. None of the States responding to the survey placed a limit on the amount of time a public service commission can take to decide on a CCN application.[7]

Depending on the State, a utility can proceed to obtain permits from other State agencies needed to construct a transmission line either before, during, or after a CCN is granted. In 11 of 33 States responding to the NGA survey, utilities are not permitted to pursue required permits from other State agencies until a final ruling on a CCN has been rendered.[8] In at least 21 States a joint certification and siting approval process has been instituted that can simplify and expedite State agency permitting issuance. At least eight States have established some sort of a siting board to coordinate and resolve permitting issues.[9]

Even with all required State agency permits in hand, a transmission line cannot be constructed until rights-of-way have been acquired for the land through which the line travels. For some projects, land acquisition for the transmission line corridor cannot be obtained voluntarily by the utility through negotiation with the landowner. Such opposition can result in the abandonment of a project or a costly rerouting unless the utility can invoke eminent domain to acquire the needed property upon payment of a court-approved level of compensation.

In a few States, utilities are granted the power of eminent domain by State law for any transmission line project, but in most the issuance of a CCN is a prerequisite before eminent domain can be exercised. According to the NGA survey, in at least 11 States the issue of whether or not eminent domain powers are granted to a utility is decided as one component of the certification and siting process. At least 20 States require a separate application and decisionmaking process for eminent domain which occurs after siting approval has been obtained.[10] In some States, the power of eminent domain is obtained from a court which considers issuance of a CCN and siting approval as evidence in its decisionmaking process.[11]

Local Permits and Approvals

Special use permits and zoning variances issued by local and county governments are commonly required before construction of a transmission line project can begin. Acquisition of local permits can be an extremely complex and time-consuming undertaking, especially in areas where significant local opposition to a transmission line project exists. A recent case study by the National Coal Council of a 50-mile transmission line project found that over 30 local and county governments had to be individually contacted regarding the project.[12] For a long-distance interstate transmission line project, separate approvals from many local government entities can be required. Each decisionmaking process generally includes an opportunity for appeal through

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[6] Public Service Commission of West Virginia, "State Survey of Transmission Certification and Siting, and Planning Processes," unpublished summary, Nov. 13, 1987, p. 8. This document provides the preliminary results of the NGA-NARUC survey of State utility and siting commissions.

[7] NGA survey, supra note 1, p. 12.

[8] Public Service Commission of West Virginia, supra note 6, p. 6.

[9] NGA survey, supra note 1, p. 7

[10] Ibid., p. 4.

[11] NGA, supra note 3, p. 11.

[12] National Coal Council, *Interstate Transmission of Electricity* (Washington, DC: June 1986), p. 33

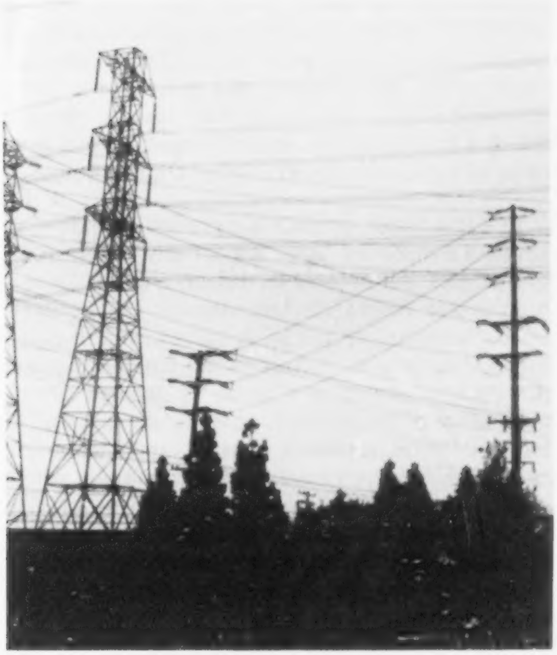

Photo credit: Casazza, Schultz & Associates, Inc.

View of multiple transmission lines

the court system in addition to the administrative review process.

As part of their certification and licensing processes, several States permit one agency to override the decisions of other agencies, including local governments. At least 17 States grant such powers,[13] but in at least 12 States, local agencies have the authority to block transmission line projects from being built within their jurisdiction.[14]

Permitting Transmission Lines Across Federal Lands

Long-distance transmission lines often cross lands administered by Federal agencies, especially in the Western United States. In most cases, siting a line on Federal lands requires obtaining a right-of-way from the administering agency in a process separate and distinct from State and local agency actions. Federal land permitting frequently involves three steps: an environmental review, a land-use planning process, and review of a specific right-of-way application.

Under section 102(2)(c) of the National Environmental Policy Act of 1969 (NEPA), an Environmental Impact Statement (EIS) must be prepared prior to any major Federal action significantly affecting the quality of the human environment. Most major transmission line projects that cross long stretches of Federal lands are considered major actions and fall under the EIS requirement.

The EIS process begins with a preliminary analysis to determine how extensive an environmental review is required by NEPA for a particular project. A "finding of no significant impact" can permit a project approval process to continue without more analysis under NEPA. If minor impacts are anticipated, an abbreviated environmental assessment is deemed adequate.

For projects with significant potential impacts, a full EIS is required to be prepared by the agency administering the land affected by the transmission line. When the lands are administered by more than one Federal agency, a lead agency is selected, but all agencies participate in and are bound by the results of the EIS. For example, for the 1984 EIS analyzing the 345-kilovolt (kV) line between the San Juan Generating Station in New Mexico and Rifle, Colorado, the Rural Electrification Administration acted as the lead agency and the U.S. Forest Service (USFS), the Bureau of Land Management (BLM), and the Western Area Power Administration served as cooperating agencies.[15]

Separate from the NEPA process, several Federal agencies, notably BLM and USFS, are responsible for providing comprehensive land-use plans for the lands under their jurisdiction and to identify areas suitable for the construction of transmission lines. Land-use plans, called Resource Management Plans, for public domain lands under control of BLM are required under the Federal Land Policy and Management Act of 1976.[16] Similarly, National Forest land-use plans are required under the National Forest Management Act of 1976. Utility corridors are frequently discussed in Regional Guides, which are prepared for each of the USFS's 10 regions and in the Land and Resource Management Plans for each National Forest. Identification of potential utility line corridors is an important part of these land-use plans because only projects sited along corridors identified as suitable for transmission lines can be approved.

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[13] NGA survey, supra note 1, p. 7.

[14] NGA, supra note 3, p. 10.

[15] Rural Electrification Administration, *Rifle to San Juan 345 kV Transmission Line and Associated Facilities: Final Environmental Impact Statement* (Washington, DC: March 1984), p. 1.

Many land-use plans, such as the recently released Farmington Resource Management Plan for the BLM administered lands in the San Juan Basin in New Mexico, employ a "window" approach to planning for transmission lines, which seeks to identify general areas where power lines might be needed and more specific areas where a conflicting land use would preempt transmission line construction. This approach provides significantly more flexibility in later line siting efforts than would exist if only specific corridor paths were approved at the land-use planning stage.

Apart from NEPA and land-use planning processes, approval of the use of Federal lands for a specific transmission line is still required from the administering Federal agency. Depending on the type of transmission line project and the categories of Federal lands involved, a number of Federal agency permits might be required. For example, the BLM issues a right-of-way permit across public lands and the USFS issues an authorizing document for a line to cross a National Forest. For lines crossing an international boundary, a permit must be obtained from the Department of Energy as the implementing agency of a 1953 Presidential Executive Order on international electricity transactions. The Department of Defense can deny a permit if it interferes with a major military installation or if it is deemed to interfere with national security. The Federal Highway Administration (FHA) must approve corridor paths along interstate highways, which is currently only done as an exception to FHA policy. The U.S. Army Corps of Engineers must issue permits for lines crossing interstate navigable waterways. The Federal Energy Regulatory Commission (FERC) must approve transmission line projects associated with Federal hydroelectric facilities.[17]

Permitting Transmission Lines Across Tribal Lands

Approval of transmission line corridors across tribal lands must be obtained from the governing tribal council or other tribal ruling body for the affected Indian lands. There is no Federal requirement for land-use planning on tribal lands, nor are there standardized procedures for applying for a right-of-way across tribal lands. Reporting requirements and the decisionmaking process employed to rule on the application vary among different tribal governments and can change markedly over time.

Utility companies cannot exercise the power of eminent domain on tribal lands even though they may have received overall approval of transmission line projects by Federal or State agencies. In eight States, tribal governments are consulted as part of the State process for transmission line certification and licensing even if tribal lands are not involved.[18]

Transmission line siting on tribal lands has proven to be very difficult in some instances, even when only sparsely populated lands are involved. For example, proposed transmission line rights-of-way from the San Juan power plant in New Mexico across the Navajo Nation, where the transmission system can be linked to the electricity demand centers in the Far West, have been debated by the Navajo Tribal Council for decades and remain a very controversial topic with no clear resolution in site.

Regardless of the decisionmaking procedure used by the tribal government, any action taken by a tribal government must also be approved by the U.S. Bureau of Indian Affairs (BIA) as the Federal trustee for tribal lands. (BIA, however, does not exercise its authority over all categories of Indian lands, e.g., allotment lands.) Because BIA approval of a permit for a large transmission line project is often ruled to be a major Federal action under NEPA, an EIS can be required for projects on tribal lands. For example, BIA has acted as the lead agency for the EIS for the proposed Olé power line in New Mexico because several proposed routes could affect Pueblo Indian lands or sacred sites within a National Forest.

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[16] Title V sets out Federal land requirements, including the shared use of rights-of-way, where possible.

[17] National Regulatory Research Institute, *Non-technical Impediments to Power Transfers* (Columbus, OH: 1987), p. 161.

[18] Public Service Commission of West Virginia, supra note 6, p. 1.

Multi-State Siting Efforts

Certification and siting of transmission lines are generally the responsibility of State regulatory agencies. For a long-distance interstate power line project, regulatory agencies in each State independently review the portion of the project within their jurisdiction. Denial of a CCN in any one State can lead to the abandonment of an entire interstate project.

An interstate transmission line project which distributes costs and benefits in many States presents a difficult problem for State regulatory agencies as they assess the overall need for the project in relation to the traditional State-specific criteria for certification. Only a few programs have been undertaken to date to bring regulatory agencies together during the planning or permitting of an interstate power line. Communication among States most frequently occurs on an informal basis through associations of State agencies such as NARUC. Other examples include the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, which in 1987 established a joint Committee on Regional Electric Power Cooperation; the National Governors Association, which has formed a Committee on Energy and Environment Task Force on Electricity Transmission; and the New England Governors' Conference, which has formed an interstate agency Power Planning Committee. Occasionally regulators from other States will be invited to observe or participate in a planning or certification process taking place in another State. Sometimes a State agency will take the initiative to intervene in a regulatory proceeding in another State.

The Federal Government currently plays only a small role in transmission line certification issues for interstate or interutility projects. Under the Federal Power Act, FERC has the authority to set the wholesale rates that utilities may charge for bulk or economy sales and wheeling. Although FERC decisions are critical in determining the overall economic viability of a long-distance power line project, it does little to assist in power line siting.

Utility companies have done the most to foster interutility planning for reliability purposes, which includes identifying the need for new long-distance transmission capacity. One institution that performs this function as part of its mandate is the North American Electric Reliability Council (NERC).

Power pools and coordination agreements among utility companies provide another forum for joint utility planning and transmission line project development. For example, both the New England Power Pool and the Pennsylvania-New Jersey-Maryland Interconnection engage in joint utility planning activities. Moreover, ad hoc interutility agreements that deal with potential transmission and reliability problems occur frequently among utility companies.[19]

With one exception, multi-State utility and State agency programs regarding long-distance transactions are voluntary. The one mandated interstate electricity planning agency—the Northwest Power Planning Council (NPPC)—was established and is guided by Federal legislation.[20] Washington, Oregon, Idaho, and Montana are the member States of NPPC, which was created by the Pacific Northwest Electric Power and Conservation Act of 1980. The Council prepares long-range electricity demand forecasts for the region and develops power supply plans capable of meeting that demand.[21]

Impediments to Transmission Line Siting

Institutional, regulatory, and legal elements of the transmission line siting process can delay extra high voltage (EHV) power line projects by adding to their completion time and cost and by contributing to the uncertainty that the required approvals will be obtained. Three potential sources of impediments are discussed in this section: 1) power line approval procedures; 2) jurisdictional complexities among agencies required to give approval to a project; and 3) the lack of multi-State coordination.

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[19] National Regulatory Research Institute, supra note 17, p. 96.

[20] NGA, supra note 3, p. 18. Pacific Northwest Electric Power Planning and Conservation Act of 1980, Public Law 96-501, 94 Stat. 2697, Dec. 5, 1980, 16 U.S.C. 839.

[21] Northwest Power Planning Council, *Western Electricity Study Briefing Paper: Interregional Transactions*, Portland, Oregon, Dec. 28, 1987, "Preface."

Obstacles to Transmission Line Approval

As noted earlier, State-mandated utility planning processes tend to have a strong focus on the need for new power plants and frequently do not analyze in depth the potential for increased long-distance interutility transmission to facilitate interutility sales as a supply option. The inherent uncertainties involved in interutility power sales, especially from another State or from Canada, often result in a low ranking of this option in long-range plans. Another shortcoming of the long-range planning process is that utilities jointly involved in development of transmission lines are not required to discuss components of the project either owned by other utilities or located out of state. State agency staff are left with the job of thoroughly scrutinizing and consolidating the project plans. The same shortcomings may often apply to long-range electricity plans produced by State regulatory agencies.

The lack of attention given to long-distance transmission projects and interutility sales during the long-range planning process contrasts sharply to the attention these issues draw in the world of actual electricity sales contracts and transmission line project development. Moreover, when the time comes for decisions about specific projects and contracts, limited analysis from past planning efforts is available.

State laws regarding the obligations of utilities and utility regulators alike often create obstacles to long-distance transmission line projects. State utility franchise laws generally place the greatest obligation on a utility to provide reliable service within its service area. This obligation provides a disincentive for a utility to consider a project such as building a power plant or transmission line which may have as its goal supplying electricity to customers of another utility.

State regulatory agency transmission line siting criteria reflect the same specificity with regard to service areas that guide most utility company actions. In assessing need for a transmission line, State public service commissions generally examine first the benefits that may accrue to the customers of the utility proposing to build the line. These benefits are then balanced against the anticipated costs of the project, including impacts on the environment, the lifestyles of affected residents, and other public interest considerations.

A difficult analytical dilemma is frequently encountered by State regulatory agencies facing an application for a long-distance transmission line project. Often the only direct benefit to the customers living in the service area through which a transmission line passes is improved reliability of electricity supply, which is impossible to quantify. The quantifiable benefits of low-cost electricity often accrue to customers living in other service areas or States outside of the agencies' jurisdictions or the scope of the application. On the other hand, local costs are obvious and quantifiable, including lifestyle and economic disruption, and aesthetic, environmental, and recreational impacts.

Balancing costs and benefits is a complicated process for State regulatory agencies, especially in some States. Wisconsin, for example, has laws which require that local or statewide benefits outweigh local costs as a condition of power line approval.[22] Many State regulatory agencies have responded by developing conservative "prudence" or public interest criteria against which to judge the merits of utility projects under review. These public interest criteria have on occasion been criticized as "highly parochial attitudes" that dampen the enthusiasm for utilities to undertake long-distance transmission line projects.[23]

Another problem utility company applicants face is that power line approval criteria can differ among agencies within a State and especially when agencies are located in different States. As a result, power companies often must file multiple applications in support of a transmission line project. Moreover, the information in each application must be tailored to fit the evaluation criteria of the agency to which it is submitted.

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[22] Ibid., p. 90.

[23] National Coal Council, supra note 12, p. 2.

Unless one agency is empowered to veto a contrary decision by another agency, a utility applicant faces several "show-stopper" regulatory review processes. An adverse decision in any one arena in any State can force the abandonment of the entire project. Furthermore, criteria used by a single agency can change, even during the process of review of one project.

A final consideration is that very few siting procedures contain any deadlines for decisionmaking. Thus, it becomes impossible to predict with confidence when a power line project approval or denial will be forthcoming. Even when deadlines are established, they usually affect only one component of the decisionmaking process, not the entire process. For example, schedules set for regulatory agency actions are completely distinct from schedules set by courts to address judicial challenges to regulatory agency actions. Scheduling problems encountered by transmission line projects have led NGA to conclude that the lack of a definitive time table for the regulatory decisions appears to be one of the biggest causes for delay.[24] (See table 7-2.)

Jurisdictional Complexities

A labyrinth of regulatory agency requirements faces the sponsors of long-distance transmission line projects. Coordination among Federal, State, and local agencies is frequently poor, and jurisdictional boundaries are often vague, leading sometimes to mismatches, overlaps, and gaps in agency responsibilities and to interagency conflicts.

Federal and tribal land administering agencies have permitting powers that exist separate from State regulatory agency approval procedures. Decisions by these agencies affect the viability of a transmission line project regardless of State agency actions. Federal and State jurisdictions mesh somewhat more closely between FERC, which sets wholesale power and wheeling rates upon which interutility sales depend, and State public utility commissions, which usually grant required project licenses. However, according to the National Regulatory Research Institute (NRRI), "there is virtually no coordination between the two entities in regard to these activities."[25]

Table 7-2—Most Important Factors Affecting Timely Consideration

Most important factors(s) promoting timely considerations:
Statutory time frame
Single agency
Ease of process
Discretionary hearings
Joint review
Information requirements
Formal planning process
Limited siting authority

Most important factor(s) hindering timely considerations:
Reviews/opposition/issues
Environmental constraints
Incomplete information
Lack of resources
Duplication of effort
Cumbersome process
Lack of deadlines
Court involvement
Other agencies involved
None

SOURCE: Summary of State Government Response to a survey by the National Governors' Association Task Force on Electricity Transmission (prepared by the staffs of the Public Utilities Commission of the State of Ohio and of the West Virginia Public Service Commission), OTA contractor report, July 1988.

Depending on the State, several State regulatory agencies can be involved in the permitting process for a large transmission line project. Although many States have established either a siting board or appointed a lead agency to coordinate the State review process, guiding an application through the regulatory apparatus can be a difficult and time-consuming task. Joint agency permitting processes remain the exception, not the rule, and because consideration of some permits is often contingent on issuance of others, agency approvals must sometimes be sought sequentially rather than simultaneously.

Participation of a multitude of local municipalities and county governments in permitting a long-distance transmission line represents another layer of jurisdictional complexity. Even in States where local decisions can be overruled by a State siting agency, local government actions are still important to the overall siting process, especially where strong local opposition makes a State agency leery of vetoing local government actions.

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[24] NGA, supra note 3, p. 23.

[25] National Regulatory Research Institute, supra note 17, p. 169.

Added to this intricate network of regulatory agency interactions is the court system. Judicial review of regulatory agency actions is a legal right of opponents to most agency decisions. Thus, depending on the agency and the decision involved, Federal, State, and local courts frequently enter the transmission line approval process and can create lengthy tangents from the regulatory agency review process.

Lack of Multi-State Coordination

Variations in transmission line approval processes among States coupled with the lack of coordination in decisionmaking and interstate information exchange can create major obstacles to long-distance power line projects. Even where there is some fledgling effort at interstate coordination, no one State agency is necessarily bound to implement a decision made as a result of multi-State planning efforts.

Coordination between State agencies and FERC is also inadequate. The current practice of independent actions by FERC and by State regulatory agencies has moved the NRRI to conclude that "the Federal-State regulatory dichotomy can be considered to be an important institutional impediment to the movement of bulk power between utilities."[26]

One problem that can result from the lack of coordination between FERC and State agencies is that State public utility commissions, as they make their cost/benefit analyses, cannot necessarily obtain needed information from FERC. Another potential problem is that State regulatory decisions with regard to interutility power projects can be affected by future FERC rulings that the agencies cannot anticipate and over which they have no control.

Interest Group Perspectives

A number of interest groups frequently interact during the siting of a transmission line. These groups include utility companies, government regulators, landowners, consumers, environmental organizations, and energy system advocates. Although the positions of these groups are molded by the individual circumstances surrounding each project, a number of perspectives are commonly associated with each group. It is the clash between these perspectives during the siting process that frequently leads to the conflicts that impede transmission line siting.

Utility Companies

At least 35 utilities in the United States now have formal public participation programs to assist in the planning of utility projects.[27] Nearly all utilities include public participation at some point in their decisionmaking regarding transmission lines.

Nonetheless, it is common for utility companies to feel that criticism of transmission line projects comes from amateurs who cannot possibly understand the economic and technical intricacies of the electric utility industry. In many respects, utilities do know more, if not best, and in adversarial environments resentment can build. Moreover, State franchise laws and historical utility standard operating practices tend to promote conservative, risk-averse attitudes on the part of many utility companies. On occasion, these attitudes can reinforce skepticism towards suggestions originating outside utility company circles, especially ideas regarding complex projects such as transmission line construction.

Government Regulators

State and Federal Government regulatory agencies respond first and foremost to the statutory mandates under which they operate. For State public utility commissions this usually means careful implementation of prudence and cost/benefit balancing concepts in transmission line siting reviews. For an environmental protection department this translates to assurance that transmission line applicants will comply with a wide range of construction and operating requirements.

A narrow perspective could develop among individual regulatory agencies with each agency focusing on its mandated responsibilities. This perspective does not necessarily foster free information exchange, cooperation, and compromise among decisionmaking authorities and also may hinder the development of a rationale for collaboration among agencies that could expedite and facilitate transmission line siting approval.

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[26] Ibid, p. 47.

[27] Westview Special Studies in Natural Resource Management, Dennis W. Ducsik (ed.), *Public Involvement in Energy Facility Planning: The Electric Utility Experience* (Boulder, CO: Westview Press, 1986), p. 5.

Landowners and Affected Populations

People who live, work, or play under or near a proposed transmission line corridor are often the most vocal interest group during the siting process. Their concerns can take many forms. If they live directly beneath the proposed path of the power line, they might be opposed to moving or they might fear that they will be inadequately compensated for the loss of their homes. These same concerns are typical if businesses, such as farm or ranch operations, are situated along a line's path. Public health concerns are also commonly encountered among people who live near an EHV transmission line.

Local opposition to a transmission line can also occur if the line is perceived to threaten noneconomic values attached to the land. Thus, for example, some Native American groups have opposed transmission lines crossing lands they hold sacred. And, subtle lifestyle disruptions caused by transmission lines, such as aesthetic degradations, can foster controversy about a project. Noneconomic concerns can cause an affected population to view as unfair the distribution of the economic costs and benefits of a transmission line project if they believe they will absorb a disproportionate share of the costs while the benefits are more widely dispersed or accrue to others altogether.

These concerns can often be addressed through careful route selection for a proposed line, extensive impact mitigation programs, and increased compensation to the affected population. Nevertheless, the perspective of the local population can solidify into nonnegotiable opposition, typified by the slogan "not in my backyard."

Ratepayer Consumer Groups

The electricity ratepayer is usually concerned chiefly with the cost of electricity at the point of end use and, to a lesser extent, with long-term reliability of supply. Under the current conditions of excess power generation capacity in many parts of the country, these concerns frequently are reflected in support of increased competition in the electric utility industry, more interutility sales, and wider interutility connections to facilitate long-distance transfer of cheap electricity. In some instances, however, concern over the cost of a transmission line project or over the future availability, cost, and reliability of supply can outweigh these protransmission expansion sentiments, leading some ratepayer organizations to oppose such projects.

Environmental Organizations

Environmental groups often take strong exception to the potentially adverse impacts of long-distance transmission lines on the visual and physical environment, wildlife, human health, and traditional lifestyles. In many instances where proposed transmission lines cross inhabited areas, the concerns of environmental groups reflect those of local landowners, particularly with regard to public health issues and the disruption of traditional lifestyles, and sacred sites.

Alternatively, environmental groups can oppose transmission line projects because they conflict with land use objectives distinct from those held by the affected population, thereby placing them in conflict with the landowners on these issues. This situation often occurs for transmission line projects proposed to cross sparsely populated lands such as National Forests and other public lands managed by the Federal Government. Rerouting and impact mitigation measures can sometimes, but not always, resolve satisfactorily many of these environmental concerns.

Energy Systems Advocates

A number of organizations promote a particular energy policy objective or technology. For example, "soft path" energy advocates believe that a combination of energy programs to promote conservation and decentralized power supply systems provides the best approach to long-term energy security in this country.[28] Similarly, trade organizations exist to promote individual energy technologies, including decentralized systems, conservation, and "hard path" coal and nuclear generating technologies.

In some instances promotion of long-distance electricity transmission and interutility power sales can be contrary to the objectives of energy systems advocates. For example, in the late 1970s, Citizens for a Better Environment opposed on technology grounds the expansion of long-distance transmission capacity to California from the Northwest partially because of a concern that the capacity would be used as a justification for the proposed construction of several large nuclear plants in Washington State.

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[28] Amory Lovins, *Soft Energy Paths* (Cambridge, MA: Ballinger Publishing Co., 1977), p. 18.

Another example is the National Coal Association's opposition to the construction of a transmission line from Quebec, Canada to an existing utility line owned by Central Maine Power Company. The Association feared the project would promote the importation and use of hydroelectric power to the detriment of coal-fired power plants.[29]

Options To Improve Transmission Line Siting

The approval of transmission line projects by regulatory agencies is a routine, although often difficult procedure. According to the NGA survey, State regulatory agencies approved 515 transmission line projects between 1976 and 1986, while denying approval for only 18. More than two-thirds of the projects approved during 1981 to 1986 have been completed.[30] The survey did not distinguish among the types of lines involved.

The success rate of power line siting notwithstanding, impediments to siting continue to draw fire from interest groups and a number of recommendations for ways to improve the siting process now enjoy considerable support in some circles. Several proposed recommendations are presented as policy options in this section.

Expanding the Planning Process

Inadequacies in the long-range planning process, especially with regard to transmission line planning, could be reduced in a number of ways. Simply providing more resources to the agencies involved in planning could help produce more comprehensive and insightful plans. Transmission line and interutility power sales issues could receive a higher priority in the planning process. The scope of planning efforts, including those submitted by individual utility companies, could be broadened to include regional and interstate electricity issues. Some entities that are frequently exempted from planning requirements, such as municipal-owned utilities and power cooperatives, could be required to participate more in the planning process.

Greater integration of planning efforts and transmission line project development could also enhance the usefulness of planning. More relevant and accurate long-range electricity plans should be of greater usefulness in determining overall project costs and benefits during the regulatory review process of specific transmission line projects. As noted by the NGA, "planning on a multi-State or regional basis can help identify even larger sources of savings from improved coordination of generation and transmission capacity development."[31]

Improved planning should help utilities anticipate land requirements for transmission line corridors farther in advance and with greater certainty of actual future need. The NGA and others have suggested that several transmission line corridors be pre-approved as part of the planning process. Creation of "resource banks" of approved corridors could provide "a bridge between the planning and transmission line certification processes to reduce the lead time for final approval" of transmission line projects, the NGA believes.[32] On the other hand, it can be argued that preselection of multiple corridors, some of which will never be used for transmission lines, can needlessly involve and upset people, lead to unnecessary changes in patterns of land use and value, and add significantly to the cost of planning.[33]

Streamlining the Regulatory Approval Process

Simplifying and shortening the process for obtaining certification and license approvals for a transmission line project from State and local regulatory agencies has undoubtedly been for years the single largest target of reformers of the siting process. Frustration with the difficulties inherent in the current system has, in part, prompted the Electric

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[29] *Coal Week*, Sept. 8, 1987, p. 8.

[30] Public Service Commission of West Virginia, supra note 6, p. 8.

[31] NGA, supra note 3, p. 18.

[32] Ibid, p. 25.

[33] National Regulatory Research Institute, supra note 17, p. 156.

Power Research Institute to develop a handbook for utilities to use as they weave through the regulatory labyrinth.[34]

One of the most frequently made suggestions is that the State siting process be coordinated by a single agency or by a Siting Board composed of members of several agencies. About 12 States have already taken this step, although the circumstances when the Boards become involved and the extent of power varies considerably.[35] This move toward "one-stop" shopping for licenses and permits has in fact expedited the siting process in many cases, but provides no guarantee that the controversy surrounding a transmission line project can be resolved. Nonetheless, the NGA has concluded that "consolidation of the approval process within a single agency (even if that agency must work with other agencies) appears to improve the predictability and certainty of the regulatory process and may increase the speed with which the State acts on project proposals."[36]

Endowing siting agencies or boards with the power to overrule decisions made by other regulatory agencies and local governments is another suggestion commonly offered to speed government review of transmission line project applications. Many States currently do authorize preemption of decisionmaking authority by some agencies, resulting, in some instances, in faster siting of transmission lines. But delays can still occur in part because of a reluctance to assert veto authority. Thus, endowing an agency with veto power may save little time and effort in the review process, but it does create a greater degree of certainty over the final outcome.

Establishment of clear criteria against which a transmission line application can be measured could also help simplify the siting process. Some States, including Florida and Montana, have established specific siting criteria, such as minimum corridor widths for power lines, based on generic issues, such as public health concerns. Greater definitiveness and specificity in siting criteria can ease the information requirements for the applying utilities and help focus the review process.

Finally, many critics of transmission line siting procedures call for the institution of firm deadlines in decisionmaking. The NGA has noted that "of those (impediments) involving State regulation, lack of a definitive time table for the regulatory process appears to be one of the biggest causes of delay."[37] On the other hand, the price tag for forcing decisions within tight schedules can be inadequate review and analysis of the issues involved. Moreover, structuring a penalty for an agency for missing a deadline poses difficulties and, as a result, deadline schemes usually act more to pressure rather than coerce agencies to act on utility applications for transmission line projects.

Involvement of Multi-State, Federal, or Independent Agencies

A final group of policy options are tailored especially for application in the siting of long-distance transmission lines that involve several States.

Increased Federal Government involvement in the siting of interstate transmission lines has been suggested as a policy option by several organizations. The National Coal Council, for example, has been very supportive of this option and has recommended that the Secretary of Energy intervene in siting cases that have interstate or regional implications.[38]

Increasing the powers of the FERC could provide another method of bolstering the Federal role in interstate transmission line siting. FERC or another Federal agency could affect siting indirectly by creating "model" siting procedures or transmission line application review criteria which could help standardize procedures used by State regulatory agencies.

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[34] EPRI, Electrical Systems Division, "A Streamlined Procedure for Obtaining Regulatory Approval for New Transmission Lines," contractor report prepared by Westinghouse Electric Corp. (EL-1404, RP-TBS79-733), December 1982.

[35] NGA, supra note 3, pp. 28-30.

[36] Ibid, p. 10.

[37] Ibid, p. 23.

[38] National Coal Council, supra note 12, attached letter to Secretary Herrington.

Expanding the Northwest Power Planning Council concept to other regions could offer another avenue to increase Federal and multi-State involvement in transmission line siting. Alternatively, congressionally approved siting "compacts" of States through which a transmission line is proposed to pass could create ad hoc multi-State decisionmaking bodies with broad siting powers. It should be noted, however, that there have been no clear examples of one State blocking the construction of an interstate transmission line.

Informal Federal-State transmission line siting dispute resolution boards could provide forums where clashing interest groups can come to discuss and possibly resolve their differences. More dramatically, some have suggested that the Federal Government or some independent dispute resolution organization, such as the American Arbitration Society, could be empowered to make decisions on issues about which regulatory agencies in different States disagreed.[39] But, the need for such a Federal role is not clear.

Enhanced Public Participation

Most utilities and State and Federal regulatory agencies have established extensive public participation programs which include participation in the review of transmission line projects. These programs seek to provide early disclosure of information and to solicit public input into the designing of utility projects. Citizen review, evaluation, advisory, and participation committees are commonly formed to help shape transmission line projects. Moreover, individual interest groups can make their opinions known through public comments, formal interventions, and legal appeal processes which occur at a number of points under most siting procedures.

Development of new models for public participation specifically geared to the circumstances commonly encountered during transmission line siting is an ongoing process which, if effective, could alleviate some impediments to siting. Toward that goal, the Edison Electric Institute convened a task force on public participation in 1982 and subsequently sponsored a lengthy study of the issue.

Conclusions

The complexities involved in the siting of large transmission line projects are significant, especially with regard to multi-State projects designed to promote interutility power sales. Nevertheless, the simple fact is that most power line projects are successfully sited in a timely fashion, if not to the satisfaction of all the interest groups participating in the decisionmaking processes. Even in the face of increased demand for new transmission capacity anticipated by electric utility industry restructuring proposals, current siting procedures are probably adequate, although inefficient.

A number of impediments to transmission line siting can be clearly identified, although sound recommendations to remove those impediments are not so obvious. A dearth of information about future transmission needs and a lack of communication among regulatory agencies appear to encourage confusion in siting processes. Conflicting regulatory agency priorities, objectives, and jurisdictions can add Byzantine elements to siting processes. Multiple decisionmaking procedures within overall siting procedures permit interest groups to pick the decisionmaking arena of their choice in which to express their views or to repeat the same concerns before different audiences recognizing that a single success can achieve their objective.

Many proposals to alter siting procedures could have negative as well as positive effects in practice, sometimes leading to solutions which create conditions as bad or worse than the problems they are designed to correct. For example, creation of "one-stop" siting entities with final decisionmaking authority can greatly simplify and expedite siting, but it can also undercut public participation, information dissemination, and the exercise of statutory responsibilities by other regulatory agencies. Bolstering long-range transmission planning can provide more useful analytical information for decisionmakers, but collection of this information can add time and costs to siting processes and identify new uncertainties and information needs.

Most of the proposals to address the impediments to transmission line siting discussed in this section are being tested to a greater or lesser degree in specific States or regions of the country. Perhaps the most prudent advice is to encourage the continuation and expansion of these efforts to improve siting procedures. Greater attention to the implementation of innovations to traditional siting protocols under virtual "test" conditions coupled with redoubled efforts to share the resulting experiences and insights could produce significant improvements to siting processes over time without undercutting along the way what appears to be a basically sound process.

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[39] National Regulatory Research Institute, supra note 17, p. 159.

ENVIRONMENTAL EFFECTS OF INCREASED COMPETITION IN THE ELECTRIC POWER INDUSTRY

The electric utility industry faces perhaps the broadest array of environmental issues of any industry in the Nation and has for many years. Because electric utilities are so pervasive in the life of the United States, and because their facilities are often so large, the industry has been at the cutting edge of environmental disputes and a leader in developing environmental control and monitoring technology.

As the industry's structure changes, either through evolution or by conscious public policy, there is no reason to believe that environmental issues will recede into the background. Indeed, it is likely that environmental concerns over generation, transmission, and distribution activities will continue to be a major element in the industry's structural dynamics under any future scenario.[40]

Generation

The major environmental impacts of electric power generation can be divided according to fuel cycle issues and combustion issues. Changes in electric power industry regulation and the structure of bulk power markets could have demonstrable impacts in these areas, and moreover, these are likely to vary in different regions of the country.[41]

Fuel-cycle issues include the impacts of extracting, processing, and transporting fuels and disposing of their wastes. The primary fuels for power generation are coal, oil, gas, uranium, and waste materials. Major concerns include the impacts on competing land uses, air and water pollution, and hazardous waste disposal. Renewable energy sources such as hydropower, wind, solar, and biomass each have their own set of environmental impacts.

Combustion issues include not only the direct impacts of generation or combustion, but also the mix of electric utility generation—the size, type, fuel, and location of generating plants. Burning fossil fuels raises a whole series of air quality issues, including control of emissions of SO_2, NO_x, CO_2, and other hazardous pollutants. Nuclear generation, of course, has a long and familiar list of environmental and public health disputes, including routine air and water emissions, reactor safety, emergency planning, and the consumptive use of water.

There is fairly widespread belief that reliance on competitive bidding for new electric power supplies could, depending on the details of the bidding process, cause a shift in the size of new plants and in fuel choices. If small supply increments, lower short-term costs, and shorter lead time projects are favored, it is likely that more oil and gas generators will be built. However, developing coal technologies—particularly atmospheric fluidized bed and integrated, combined-cycle coal gasification—that are targeted at smaller, modular units could eventually be competitive for cogeneration and utility applications. Under other bidding structures, larger plants with perhaps lower long-term costs might be able to compete more effectively.

Size and fuel choices can be important environmentally. Until quite recently, air pollution regulations subjected smaller boilers (i.e., less than 67 megawatts) to much more lenient sulfur dioxide standards than large boilers. But as a result of a lawsuit brought by the Natural Resources Defense Council and settled late in 1987, the 1.2 pounds per million Btu SO_2 standard and 90 percent emissions reduction rule will apply to all fossil-fueled boilers above about 27 megawatts.[42] And EPA is on a schedule to apply the 1.2 standard to even smaller coal-fired plants by 1989.[43]

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[40] Much of the information in this section is drawn from an OTA contractor report, Kennedy P. Maize, "Environmental Effects of Increased Competition in the Electric Power Industry," May 1988.

[41] See also the discussion in ch. 6.

[42] While 27 megawatts is rather large for a gas-fired combustion turbine or combined-cycle project, it is on the smaller side for coal-fired boilers.

Transmission and Distribution

Transmission and distribution have their own set of environmental issues. While these issues haven't received the national attention accorded air quality and waste disposal, they have often been just as intense and fractious at the local level as the more traditional environmental disputes. Transmission issues may become a greater part of the environmental debate in the future, as utilities change their spending patterns away from building plant and toward moving power.

Transmission and to a lesser extent distribution are intimately tied into local land use and zoning, and disputes often take place in the institutional forums created for dealing with local problems, such as city, county, and State zoning boards, boards of zoning appeals, and the like. Other venues for land use disputes over transmission and distribution can occur before State bodies that must license or permit a facility, in an eminent domain proceeding, or in State courts.[44] If Federal lands are crossed, Federal land management agencies will be involved. Landowners who will see power lines cross their property, particularly in urban or suburban areas but also in rural areas, often believe the line will lower the value of their property.[45] Consequently, the disputes can be very bitter and intense.

Because power lines can extend for long distances, are often highly visible, and frequently pass through populated areas, the siting process can be a time-consuming, politically fractious, and frustrating experience for the utility, regulators, and local citizens. The economic impacts of siting decisions on affected landowners can be direct and costly.[46] After the project has been sited and permitted, there can also be environmental disputes related to the impacts of construction, including issues such as erosion and sediment control, soil compaction, destruction of forests, and the like.[47]

Once a power line is built and operating, a different set of impacts comes into play, although these issues likely will have been raised earlier during the siting and permitting processes. These include visual impact, impacts on bird life,[48] audible noise,[49] corona effects,[50] and, an area that has generated a lot of attention of late, the effects of electrical and magnetic fields on wildlife, livestock, and human health.[51] Another environmental issue related to existing power lines is the use of pesticides and herbicides to clear rights-of-way.

Visual impacts play a major role in transmission line disputes, in part because the visual presence of the lines often becomes a symbol of its total presence. Figure 7-1 shows the dimensions of typical 345-kV transmission line towers. The utility industry has attempted to design less visible structures, although that can drive up costs. Some analysts have suggested that the presence of a visible line is "a negative feedback mechanism" that could serve to slow growth of electrical use, by symbolizing to consumers the costs associated with electricity use.[52]

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[43] Telephone interview with David Hawkins, NRDC, Jan. 7, 1988. Plants with a capacity factor of less than 30 percent and plants burning very low sulfur oil are exempted from the percentage reduction requirements. See also, American Public Power Association, "Small power plants now must meet pollution standards," *American Public Power Weekly*, Jan. 11, 1988.

[44] See the discussion of the siting process elsewhere in this chapter.

[45] Robert R. Thompson and William E. Phillips, "Agricultural Land Value Changes From Electric Transmission Lines: Implications for Compensation," *Right of Way*, December 1985, pp. 24-27.

[46] See, for example, the remarks of Richard Disbrow, President, American Electric Power Service Corp., OTA workshop, Sept. 28, 1987.

[47] For a good discussion of the environmental impacts of powerlines, see Federal Colstrip Transmission Corridor Study Project Team, "Developing Numerical Values to Estimate Potential Environmental Impact of Power Transmission Corridors," Bonneville Power Administration, November 1978, Appendix.

[48] Rene Males, *EPRI Journal*, March 1980, p. 49.

[49] John A. Molina et al., "Modification of Transmission Line Audible Noise Spectra to Reduce Environmental Impact," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-100, No. 4, April 1981.

[50] Air ionized by the high electric fields at the surface of the conductor creates the corona phenomena.

[51] For a discussion of the evolution of environmental concerns about power lines, see William E. Feero, "The Evolution of Electromagnetic Effects Issues," paper presented at the International Utility Symposium on Health Effects of Electric and Magnetic Fields, Sept. 16-19, 1986, Toronto, Canada.

Existing power lines can have an adverse impact on bird populations, including protected species such as the golden eagle, which use poles as perches for hunting and are often electrocuted by contact with lines. There is also some evidence that overhead lines may increase avian mortality from collisions and changes in behavior, although not much data on this problem has been accumulated.[53]

The physical presence of power lines is associated with what are sometimes referred to as "nuisance" effects that are annoying or unpleasant to those living or working around them. Corona discharges from power lines create audible noise and interfere with radio and television frequencies. Corona discharge is largely a function of weather, posing greater problems in rain or fog.[54] Corona noise is typically both low-frequency hums and buzzes, and random, high-frequency hisses and crackling. Studies suggest that the high-frequency component is more objectionable to listeners.[55]

Another product of corona discharge is ozone, a powerful oxidant that can affect living tissue. Ozone is similar to ionizing radiation, in that it causes tissues to break down and undergo chemical change. It can irritate eyes, lungs, and circulatory systems of animals, including humans, and increase susceptibility to infection and chronic disease through stress. It can also cause direct damage to vegetation.

Power lines may also have a more subtle impact on health. A number of studies have demonstrated effects on cells, animals, and humans from exposure to extremely low-frequency fields such as those generated by power lines and household appliances. The electric utility industry is devoting a greater share of its research dollars to this emerging field, trying to pin down the mechanisms that are at work, and determine what steps can be taken to prevent damage if it is occurring.[56]

Finally, maintenance and vegetation management can have environmental impacts with existing transmission lines. Utilities generally want to establish a shrubland environment under their power lines, because shrublands last far longer than grasslands, once undesirable trees are removed. Since the 1940s, utilities have applied chemical herbicides to control vegetation. Information is lacking on the effects of chemical herbicide treatment beyond the initial brownout that results.[57]

Scenarios of Change in the Electric Utility Industry

Structural changes in the electric power industry could have different environmental consequences. These impacts are difficult to discern in light of the speculative nature of the proposals. Despite the inability to pin down the impacts with precision, it is possible to describe how OTA's five scenarios (see ch. 3) might affect the environment.

Scenario 1: Reaffirming the Regulatory Compact

As with all the scenarios, scenario 1 presents both environmental problems and opportunities. The environmental advantages flow from the fact that scenario 1 is well understood. As essentially the status quo with slight modifications, the first scenario presents issues that have been faced in the past and relies on institutional arrangements that have been developed over the past 20 years. With this scenario, most environmental issues are known.

The concept of "rolling prudence" has some potential environmental benefits. It might prove easier to cancel some projects earlier in the construction process, before such enormous amounts of capital have been sunk in a project that cancellation becomes politically difficult. Prudence is a doctrine

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[52] Thomas W. Smith et al., *Transmission Lines: Environmental and Public Policy Considerations*, Institute for Environmental Studies, University of Wisconsin-Madison, June 1977, p. 44.

[53] Males, supra note 48. Of course large birds also can have minor, but harmful impacts on transmission lines. EPRI, "A Joint Utility Investigation of Unexplained Transmission Line Outages," (EL-5735) Final Report, May 1988, Palo Alto, CA.

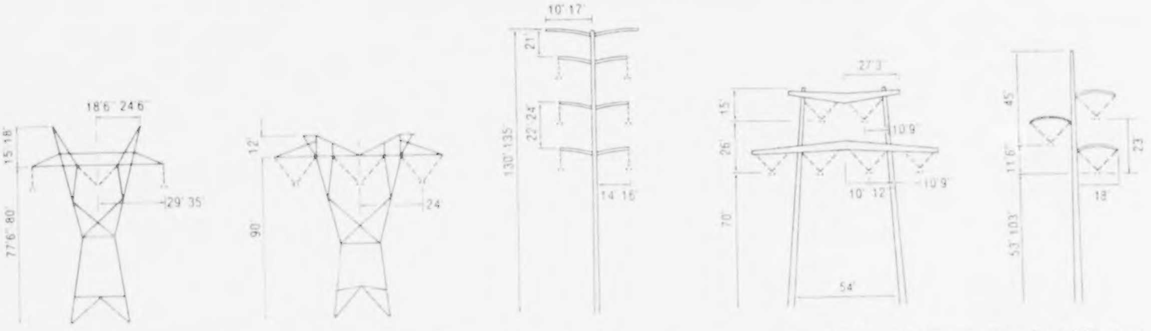
[54] Smith et al., supra note 52, p. 39.

[55] Molina et al., supra note 49, p. 2122.

[56] "EMF: The Debate on Health Effects," *EPRI Journal*, vol. 12, No. 7, October/November 1987, pp. 4-15. See also, Mari H. Malakoff, "Electronic Smog," *Not Man Apart*, March-April 1988, pp. 10-11.

[57] Smith et al., supra note 52, p. 32.

Figure 7-1—Dimensions of Typical 345-kV Transmission Lines



SOURCE: Office of Technology Assessment adapted from Electric Power Research Institute, *Transmission Line Reference Book: 345 kV and Above*, 2d ed. (Palo Alto, CA: Research Reports Center, 1982).

that utility commissions have rediscovered recently and applied with various effect. However, the findings of imprudence necessarily come too late to prevent expenditures which should never have been made.

Utilities complain that post-construction prudence determinations subject them to too much financial risk, and there is merit in that complaint. But many regulators, consumer groups, and environmentalists are also critical of the current system because it allowed construction to continue on a number of nuclear and coal plants that later proved to be imprudent because of their extreme costs or excess capacity. Carefully designed, periodic prudence reviews could provide an institutional mechanism to prevent unneeded, socially costly, and environmentally damaging plants from being built.

The periodic reviews might also be a way to factor in technological advances made during the course of plant construction. Under the current system, once a plant design is finished, it can be difficult to persuade the utility to alter it voluntarily to incorporate advances in pollution control technology. Reviews during the process might provide a way to update the plant plans and apply the best available technology. State assurances of recovery of prudent expenditures would offer additional incentives.

Scenario 1 is not without environmental problems, but those problems are largely similar to those under the status quo.

The down side to scenario 1 and the status quo, from an environmental standpoint, is the incentive it gives to the continued operation of some of the oldest and dirtiest coal-burning power facilities, which are among the primary targets of acid rain cleanup proposals. For example, Cleveland Electric Illuminating's Eastlake plant has a State emission limit of 5.64 pounds per million Btu and the Avon plant has a 4.65 pound limit, in contrast, the new source performance standard is 1.2 pounds. Other older plants around the country have even higher emissions limits under State Implementation Plans.[58]

The 1970 Clean Air Act (as amended in 1977) was premised on the belief that most older plants would be replaced after their 30-year book lifetime. Consequently, the act relies on the new source performance standards for its regulatory bite, rather than on pressing for improved environmental performance of existing plants.

The economic landscape in the years since Congress passed the Clean Air Act has favored keeping existing plants on line and avoiding building new ones. This was driven partly by the costs of pollution control on new plants, but more directly by unusually high interest rates of the 1970s, coupled with declining and unpredictable load growth. Power plant life-extension and geriatric programs have become a major focus of savvy utilities, and some experts believe that it may be possible to keep old plants in service almost indefinitely.[59] Under the Clean Air Act, if the cost of a life-extension program exceeds 50 percent of a "comparable new facility," the plant may be subject to New Source Performance Standards (NSPS). According to the Electric Power Research Institute: "This regulation has not yet been tested, and utilities are unsure whether the 50 percent trigger refers only to a one-time capital expenditure or to aggregated refurbishment costs over several years."[60]

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[58] Figures are from an interview with Centerior Energy's environmental department by Kennedy Maize, OTA contractor, Apr. 18, 1988.

The status quo offers a strong incentive for utilities to keep the oldest, and often dirtiest, plants on line as long as possible. In extending the life of existing plants, the utility avoids siting disputes, heavy capital requirements, prudence reviews, and major disallowances. By contrast, some of the other scenarios might encourage utilities to close the facilities if they can get power cheaper from QFs or independent producers, can raise capital relatively inexpensively, or can avoid the need for prudence reviews and rate basing entirely by building a deregulated plant.

Scenario 2: Expanding Transmission Access in the Existing Institutional Structure

From an environmental perspective, this scenario could have some favorable and some troubling consequences. On the positive side, it would be possible to build environmental considerations into the public interest standard for wheeling orders. For example, it might further environmental goals to wheel in power from remote sites to avoid burning coal or oil in an urban environment. Increased wheeling could lead to construction of fewer baseload plants and a more flexible electric supply system, better able to accommodate advanced renewable technologies such as photovoltaics. Greater wheeling and stronger interconnected transmission grids could avoid situations such as today's power surplus in the South and Midwest while the Northeast faces potential power shortages.[61]

Scenario 2 also has potentially negative environmental consequences. If expanding transmission access is successful, presumably more transmission capacity will be constructed. Utilities would have to plan for third-party transmission in their system planning of power lines. The result likely would be plans for more transmission lines, with concomitant disputes over siting and construction. Some utilities might see transmission as a new business opportunity and build transmission marketing into their plans. Siting, building, and operating electricity transmission has both well-understood and frontier environmental problems, ranging from land use to public health issues associated with extremely low-frequency fields.

Access to transmission services and expanded competition might also encourage unneeded plant construction, both by independent power producers (IPPs) and QFs. If electric utilities see selling transmission services as a business opportunity, rival utilities might get into price wars attempting to lure generators into their grids. That could lead to construction of plants beyond what would occur simply to supply the PURPA market if transmission continued to be closely guarded.

The availability of wheeling and expanded QF eligibility could cause a shift in the generation mix. It is not known how this change might affect the nature and distribution of environmental impacts of power generation. Based on early experience among QFs, it has often been presumed that QFs and IPPs would rely heavily on gas-fired combustion turbines, with perhaps some combined-cycle generation as well, but initial results of State competitive solicitations somewhat belie this presumption. See box 7-A: Bidding in Massachusetts: A Glimpse of the Future? While natural gas is the cleanest burning fossil fuel, it is not entirely devoid of pollutants. In nonattainment areas, increased local generation could lead to further tension and disputes over pollution offsets and lowest achievable emission rates (LAER). In attainment areas, increased genera-

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[59] "Longer Life for Fossil Fuel Plants," *EPRI Journal*, vol. 12, No. 5, July/August 1987, pp. 21-27.

[60] Ibid, p. 26. Also, the plant could be subject to NSPS if the emission rate of any of the criteria pollutants is increased as a result of the life-extension program.

[61] See New England Governors' Conference, "A Plan for Meeting New England's Electric Needs," December 1986. For a powerful critique of this view see New England Energy Policy Council, "Power to Spare: A Plan for Increasing New England's Competitiveness Through Energy Efficiency," July 1987.

Box 7-A—Bidding in Massachusetts: A Glimpse of the Future?

The Commonwealth of Massachusetts has been one of the pioneers in implementing a bidding scheme for allocating generation under PURPA. The State's department of public utilities issued its first set of competitive bidding regulations in late 1986, and the first contracts have been awarded. The State and its utilities are now working on a second round of bidding, with somewhat changed circumstances.[1]

The bidding process begins with supply and demand plans for each utility filed with the state's Facility Siting Council. Based on its plan, the utility forecasts what its next supply addition will be. If, for example, the utility were to conclude that the next plant addition it would build to meet projected demand would be a 200-megawatt, combined-cycle facility, then the utility would attempt to solicit 200 megawatts of supply from QFs, to avoid that new facility.

Massachusetts regulations stipulate how to calculate costs of the new generating capacity, including system fuel costs and capital costs. That determination, which is the equivalent to the avoided cost, becomes the ceiling price for the bidding process or the maximum bid that the utility will accept from QFs.

The Massachusetts program uses a standard contract, developed by the Department of Public Utilities (DPU), against which the suppliers are to bid. The utility can include "nonprice" elements in its solicitation and bid-evaluation process. This is where the utility can build in environmental constraints, or other special conditions such as reliability, dispatchability, fuel diversity, preferred locations, and the like. The standard contract provides a baseline, but the final contract does allow for negotiation as long as DPU is able to exercise oversight.

The current bid system does not include provisions for conservation and load management. That thorny issue, along with the issue of how to treat non-QF facilities, is currently the focus of another regulatory proceeding, underway at DPU.

It is important to note that Massachusetts already requires wheeling within the State, on the basis of an open, published tariff. If a QF in the western part of the State wins an award from Boston Edison, State regulations require the intervening utilities to wheel the power.

The Experience To Date

Boston Edison Co. was the first utility to complete the full cycle, from initial solicitation with the company expecting to have contracts for 344 MW of power from nine separate projects (see table 7-3). Boston Edison originally sought only 200 MW, but received bids for 1,860 MW. The levelized ceiling price for the bid was 8.7 cents per kWh, and the successful bids tendered at between 6 and 6.5 cents. The first eight low bidders came in at a total of 144 MW, but the ninth bidder offered 200 MW. After some negotiations among the parties, Massachusetts DPU concluded that Boston Edison could go forward with the nine bidders. Later, even though several projects dropped out, contracts were signed for a total of 416 MW.[2]

To prevent a repetition of California's early experience with its Standard Offer No. 4, where as many as a third of the bidders turned out to be speculative projects that likely never would have been built, Massachusetts' regulations require that the QF put up a $15 per kW deposit as earnest money at the contract signing.

From an environmental standpoint, the winning projects do not support assumptions that bidding will necessarily result in a better fuel mix or greater environmental protection than conventional avoided cost determinations.

First, the 200-MW coal-fired facility belies the widely shared expectation that gas would be the preferred fuel for QFs and IPPs. It is also important to note that the original bid for the 200-MW atmospheric fluidized bed facility proposed a site in East Boston, a small, highly urbanized area. Subsequently, the project developers decided that perhaps an inner-city site wasn't such a good idea and proposed two alternative sites for the project. As of November 1988, the plant remained unsited.

Some 35 MW are to come from waste-to-energy plants. The Clean Harbors project would burn hazardous wastes in a rotary kiln, raise steam, and sell power to Boston Edison, but whether the project will ever be licensed

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[1] Much of this information is based on interviews by OTA contractor Kennedy Maize with Henry Yoshimura of the Massachusetts Department of Public Utilities and with John Whippen, manager of energy resource planning and forecasting, Boston Edison Co.

[2] "NEES Pulls 4 Winning Projects out of Boston Edison Solicitation," *Electric Utility Week*, Nov. 21, 1988, p. 19.

Continued on next page

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is clearly a legitimate question. The Webster mass burn facility is already running into the predictable siting disputes, which threaten to derail or delay the project. It's future is also clouded because the developers have filed for reorganization under protection of the bankruptcy court. The Wheelabrator project is one of several proposals to burn construction wastes or "urban woods." Construction wastes would appear to offer a higher quality fuel stream than conventional mixed trash. It might also be a cleaner waste stream, although one could postulate some environmental problems with construction trash, particularly with air emissions and ash toxicity from burning lumber treated to resist termites. Another problem could be associated with the amount of gypsum wallboard in the waste stream. Burning gypsum could cause serious sulfur dioxide problems. It too remains unsited.

There is an interesting irony in the four cogeneration projects offered by the New England Electric System (NEES). While NEES has been among the utilities that have been pushing the FERC to embark on an all sources bidding scheme,[3] the company has been less enamored of bidding for QF power at home. NEES argued in the Massachusetts proceeding that it could get more and cheaper power by negotiated contract rather than open bidding. The DPU gave the company an exemption from its bidding procedures in return for NEES agreements on more stringent wheeling procedures and to a provision that the company must demonstrate that it obtains more power for less money by negotiations. Thus DPU and other utility officials were surprised when NEES was a major bidder for the Boston Edison contract. NEES subsequently dropped its four winning project because of siting difficulties.

The technological mix that resulted from the first Boston Edison Request for Proposal (RFP) was probably a result of bonus points the company awarded in the nonprice section for fuel diversity. "We had established certain objectives we wanted to pursue" in the first RFP, said a Boston Edison official, "that included the promotion of fuel diversity."[4]

Boston Edison plans to revise its RFP over the next few months, to match an updated resource plan and will then file RFP No. 2 with DPU. While the new RFP will be "philosophically" the same, it will be less price intensive, and push several nonprice issues.

Anticipating regulatory changes,[5] Boston Edison likely will push environmental performance by providing target pollutant levels, with a bonus for commitments by bidders to exceed those targets. The RFP, for example, might specify a 1.2 pounds per million Btu standard for SO_2 emission, and give a bonus for a commitment to exceed by 110 percent.

Boston Edison is also pondering how to build conservation and load management bids into RFP, probably by targeting specific loads the utility wants to reduce. Utility planners hope to have some version of a negawatt bidding system in place.

Other Massachusetts utilities are not as far down the bidding road as Boston Edison. The DPU has approved the following supply additions, and ceiling prices, for the participating utilities:

Cambridge Electric Light Co: 33 MW - 7.33 cents per kWh
Commonwealth Electric: 76 MW - 6.52 cents per kWh
Eastern Edison: 30 MW - 6.86 cents per kWh
Fitchberg Gas & Electric: 11.7 MW - 7.69 cents per kWh
Nantucket Electric: 3.6 MW - 7.8 cents per kWh
Western Massachusetts Elec.: 40 MW - 5.8 cents per kWh

Clearly, capacity bidding in Massachusetts has not proceeded far enough yet to make any firm conclusions about how it is working from an environmental standpoint. However, the first Boston Edison bids had some troubling aspects because of the unexpected presence of a large coal-fired plant and the proliferation of waste-to-energy projects. The second round of bids, driven by tough new pollution rules, could be better. It will be worth watching what goes on in Massachusetts as a harbinger of what might occur as a result of the FERC bidding initiative.

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[3] Bill Rankin, "FERC Competitive Bidding Plan Splits The Utility Industry," *Energy Daily*, vol. 15, No. 171, Sept. 9, 1987, p. 1

[4] Whippen, supra note 1.

[5] Massachusetts in 1985 passed an acid rain control law that will require substantial sulfur dioxide emission reductions by 1995. The law requires an average emission rate of all utilities in the State of less than 1.2 pounds of SO_2 per million Btu. New England Power, the NEES generating subsidiary expects that it will have to reduce emissions from its Massachusetts facilities by as much as 46,000 tons per year. New England Power Fact Sheet, "Using Natural Gas at New England Power Company's Brayton Point State to Meet Massachusetts Acid Rain Law Requirements," Jan. 18, 1988.

Table 7-3—Boston Edison Company—Winning Bidders—RFP No. 1

Project	Size	Technology
FHN Energy (w/ Dominion Resources)	200 MW	Coal-AFB
Clean Harbors	2.5 MW	Hazardous waste
Bellingham	68 MW	Gas-combined cycle
NEES-cogen	3.3 MW	Combustion turbine
NEES-cogen	3.3 MW	Combustion turbine
NEES-cogen	24.5 MW	Gas-combined cycle
NEES-cogen	10 MW	Gas-combined cycle
Webster Resource	7.4 MW	Trash-mass burn
Wheelabrator Energy System	25 MW	Construction debris (aka "urban woods")
Total	344 MW	

NOTE: More recent developments have cast even greater undertainty over the results of the first round bidding. According to *Electric Utility Week*, NEES dropped its four winning projects because of siting difficulties and two projects, including the large coal plant and the urban woods project, remain unsited. Even so, contracts have been signed for a total of 416 MW. (*Electric Utility Week*, Nov. 21, 1988, p. 19.)

tion would consume some of the PSD increments available for other kinds of industrial development.

Greater access to transmission could stimulate the development of trash-to-energy projects by creating a broader market for their power. That could lead to even greater contention over waste-to-energy projects at the local and national level.[62]

Greater access to transmission could also slow individual utility conservation and load management programs and complicate the analysis that goes into conservation and load management planning. It might become necessary to create regional conservation and load management institutions, such as the power pools and NERC, to match conservation and load management planning with regional transmission and generation planning. This is what has happened in the Pacific Northwest as a result of the 1981 Northwest Power Planning Act.

Scenario 3: Competition for New Bulk Power Supplies

From an environmental standpoint, there is probably more known about scenario 3 than some of the others, because more thought and effort has gone into it at both the Federal and State level. At least seven States have implemented bidding systems of some sort.[63] FERC has commissioned two environmental studies in connection with its notices of proposed rulemaking (NOPRs) on competitive bidding and independent power producers. An environmental report done for FERC by Oak Ridge National Laboratory before release of NOPRs identified potentially significant environmental impacts from the proposals, particularly increased use of coal in four States, New York, New Jersey, Virginia, and California.[64] As a result, FERC agreed to prepare a full nationwide Environmental Impact Statement as part of its rulemaking.

Scenario 3 offers some potential environmental benefits, chiefly the prospect of more rapid replacement of the older plants with new plants, which are likely to be less polluting. The scenario implicitly assumes that "new" power will eventually drive out "old" because new, "competitively priced" generation will be cheaper and because old plants will be phased out on some actuarial basis. But if the guaranteed rate of return to the old plants, particularly those that are fully depreciated, exceeds the return on investment available in the competitive market, those assumptions may not hold, and old plants may continue to be a problem.

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[62] See Neil Seidman, "Garbage In, Garbage Out," *Not Man Apart*, November-December 1986, pp. 10-11, for an environmental critique of mass burn projects. The Institute for Local Self Reliance has a study of transmission and waste-to-energy projects currently underway.

[63] Colorado, Maine, Massachusetts, New Jersey, New York, Texas, and Virginia.

[64] "Environmental Report: Regulations Governing Bidding Programs" (Docket No. RM88-5-000) and "Regulations Governing Independent Power Producers (Docket No. RM88-4-000)," Oak Ridge National Laboratory, March 1988.

One environmental issue will be whether and how to treat plant geriatric work in the context of bidding. If a utility is required to bid the added supply associated with a particular life-extension project, it starts with an asset owned by the ratepayers. Even if fully depreciated, the plant would still have a market value. If the market value of the plant isn't factored into the bid price, the utility could reap a windfall profit from the life extension, a further incentive to keep old plants on line. This is similar to the problem posed by a deregulation scheme that allows a utility to spin off its existing plant into a deregulated subsidiary and then bid the power from that plant against new construction in the power auction. In both cases, it is necessary to factor in the value of the existing asset in order to avoid subsidizing older, presumably dirtier, plants.

Two other environmental issues are particularly pertinent to the concepts of all source bidding to supply utilities with power. The first is how to factor environmental considerations into the bidding process, and the second is how to square the bidding schemes (a supply-side issue with conservation and load management demand-side issues). The second issue may prove to be the most difficult to deal with, although not insurmountable.

In the States that have addressed the bidding schemes so far, environmental issues generally have been treated as "nonprice" factors.[65] Other nonprice factors include such things as reliability, dispatchability, and fuel diversity. The difficulty with the nonprice factors is that they introduce an element of subjectivity to the selection of the winning bidder, and take away from the auction aspects of the bidding process. That means there will continue to be a need for regulatory review to make sure that the subjective judgments of the utility don't adversely bias the decisions. It is also possible that nonprice factors will be given less emphasis than the more easily quantifiable price elements in the bids.

In cases where there is a larger policy issue—such as, for some, fuel diversity—the bidding process might have to be altered somewhat to reflect this. In New York, for example, Long Lake Energy Company, a hydro developer, suggested that, in view of the public policy in favor of developing renewable sources of energy, the State require separate requests for proposals for renewable projects during the bidding. Otherwise, the company said, a capital-intensive project such as hydro might not be competitive on a price-only basis.[66]

One of the major considerations in any competitive scenario is the desire to establish a level playing field for all competitors. From an environmental perspective, an important consideration will be whether all the players—utilities, IPPs, and QFs—are required to meet the same high environmental standards.[67]

Building environmental concerns into a bidding process as a subjective factor at least provides a conceptual way to make sure that awards are environmentally sound. But including conservation and load management raises far more difficult issues. So far, States have approached the problem in different ways.

In New York, the State PSC adopted a staff proposal to require utilities to establish bidding auctions for demand-side management.[68] An administrative law judge earlier had rejected the State PSC staff proposal for "negawatt bidding," in which a purveyor of conservation and load management could bid measures to reduce the utility's consumption by the proposed supply increment, and ruled that demand-side management not be included in the same bidding process with supply auctions.[69] The judge cited the imperfect equivalence of demand reductions and supply additions and the potential loss of utility revenues. In Maine, demand-side options were allowed to compete to provide needed increments of electricity supply.[70]

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[65] See testimony of Robert J. Keegan, Commissioner, Massachusetts Department of Public Utilities, before the Senate Energy and Natural Resources Committee, Feb. 4, 1988, p. 8.

[66] ALJ Frank S. Robinson, Case 29409, *Recommended Decision on Bidding, Avoided Cost Bidding, and Open Wheeling*, p. 65.

[67] In its brief to the New York Public Service Commission on that State's bidding rulemaking, Orange & Rockland Utilities argued that "to hold utilities to higher environmental standards would provide IPPs with an unfair and possibly deceptive economic advantage: customers could be receiving an ostensible benefit in their utility bills, with a hidden cost to the State's environment." Robinson, supra note 66, p. 66.

[68] New York State Public Service Commission, Case 29409, Opinion No. 88-15, mimeo, pp. 21-22.

[69] Robinson, supra note 66, p. 53.

FERC's proposed rule on bidding under PURPA does not provide for bidding of conservation and load management. Economist Paul Joskow of the Massachusetts Institute of Technology has argued that FERC is correct to avoid the negawatt issue. Including demand-side options in the FERC proposal, Joskow told a congressional subcommittee, "could result in higher electricity rates, inequitable electricity rates, windfall profits for some conservation suppliers, and incentives for inefficient conservation investments." But Ralph Cavanagh of the Natural Resources Defense Council told the same committee that omitting demand-side options from the rulemaking would "exclude from power supply competitions the least expensive resources available to modern electricity systems."[71]

Despite the objections, demand-side bidding is a powerful idea for stimulating energy conservation in a market-oriented industry structure. More analytic work, and perhaps some practical experiments, are needed to test whether the barriers that critics raise are real or fiction. Some suggest that negawatt bidding can work by targeting specific loads for reductions, such as motor efficiency, lighting, or buildings.

Scenario 4: All Source Competition for All Bulk Power Supplies With Generation Segregated From Transmission and Distribution Services

Both scenario 4 and scenario 5 are considerably further from the status quo than any of the predecessors. Consequently, trying to divine their environmental impacts is a speculative enterprise at best. Nevertheless, several environmental questions present themselves with this full-fledged revolution in the electric utility industry: the older plant problem, how to build in environmental analysis, and the problem of demand-side management.

Scenario 4 could present the most powerful incentives yet to continue using older, dirtier plants. If existing plants and life-extension projects can be bid to supply generation on the same basis as other sources, utilities will doubtless argue that since their older plants are fully (or nearly) depreciated, they are the low-cost bidders, ignoring the market value that the plant possesses. The result is a powerful subsidy for the fully amortized plant, even if a considerable amount is spent in life extension. (There is a similar problem in scenario 3.) This incentive could frustrate long-standing environmental goals, embodied in statutes such as the Clean Air Act and the Clean Water Act, of replacing aging, more polluting plants with new, less polluting industrial plants.

One method of reducing the potential competitive advantages of older plants is to structure the transition to scenario 4 so that the market value of the existing plant and equipment gets recognized in the market price of power from those plants. After all, one can make a powerful argument that it is the public, in the form of the ratepayers, who own the plant, since they paid for it.

One way to deal with this problem would be to force newly segregated generating companies to bid against others for ownership of the generating plants of its integrated utility predecessor. Another alternative would credit or debit the utility's rate base for any difference between the net book value of the asset and its sale price. The new owner would do the geriatric work and use the refurbished unit to enter the market.[72]

This scenario also faces the familiar problem of how to factor environmental analysis into the competitive process. Again, this is related to the larger problem of older plants with less sophisticated pollution control devices that likely would have a cost advantage in bidding. A new plant, for example, would have to obtain site approval and a host of permits that would not burden the existing plant.

A new plant sited in a nonattainment area would have to go over the costly LAER (lowest achievable emission rate) hurdle, obtain pollution offsets, and the like. In an attainment area, the new plant would have to go through the PSD process. An existing plant competing against those new plants could avoid any of those costs, as well as the high capital costs of scrubbers, bag houses, precipitators, and the like. It will require considerable regulatory ingenuity to figure out how to put the existing plant and new plants on an environmentally level playing field in this scenario.

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[70] Maine Public Utilities Commissioner David Moskovitz would deal with the imperfect equivalence problem by tying a utility's rate of return to relative reductions in the average bills paid by residential customers, and to reductions in electricity use per square foot by commercial customers. Thus, the lost revenues from conservation would be offset by higher returns on the remaining business. Aviva Freudman, "Moskovitz's Modest Proposal: Reward Utilities for Reducing Customers' Bills," *Energy Daily*, vol. 16, No. 72, Apr. 15, 1988, p. 1.

[71] Dennis Wamsted, "Negawatts or Negafood? A Demand-Side Dichotomy," *Energy Daily*, vol. 16, No. 63, Apr. 4, 1988, p. 1.

[72] Robinson, supra note 66, p. 55.

Finally, there is the conundrum of how to carry on conservation and demand-side management in an economic environment that is almost completely supply side. In a nonintegrated market, with generation separated from transmission and distribution, it is not very clear just who will worry about conservation and reducing demand. The distribution companies or "discos" will be less concerned, because they no longer face the risks of construction which have driven much industry concern about demand management. Potentially, discos will make money only if they sell power and pass through the costs of purchased power. If the equivalence between demand reduction and supply addition is imperfect in scenario 3, it is even less so in scenario 4. Clearly, the interest of the generating company (genco) will be to generate and sell megawatts. The scenario might also reduce pressure on State regulators to push for conservation and demand management if their retail ratesetting influence over wholesale transactions is curtailed.

Scenario 5: Common Carrier Transmission Services in a Disaggregated, Market-Oriented, Electric Power Industry

In addition to the environmental issues raised with regard to scenario 4, scenario 5 has some unique environmental problem areas. The knotty issue of conservation and load management becomes even more intractable in a conventional sense. With transmission companies (transcos) now in the market, making their money from selling transportation services, another force has been removed from the conservation and load management equation and added to the supply ledger. Now only the regulated distribution utility—probably serving a captive and bypassed residential and small commercial market—will have any incentive to push demand-side measures. And as long as the disco can buy power cheap enough to make a reasonable rate of return on sales, all incentive for conservation and load management disappears.

Scenario 5 also raises the specter of reduced maintenance of power generating equipment. In the rush to compete, particularly if the competition seriously drives down prices and profit margins, generating companies may decided to cut costs by skimping on maintenance. This can have disastrous environmental and health consequences. In this regard, the electric utility industry could come to resemble the deregulated U.S. airline industry, where the need to pay careful attention to costs has increased pressures on the maintenance decision-making process.[73]

This issue is not present in prior scenarios, because in each case, some strong institutional entity remains with a vested interest in reliability and maintenance. Even in scenario 4, the integrated transmission-distribution companies have a need for high reliability standards.

But in scenario 5, the only entity with an overriding interest in reliability appears to be the distribution company. For both the genco and the transco, reliability becomes solely an economic issue. Freed from its obligation to serve, if it makes more economic sense to walk away from a market than to continue to sell to it (as a result, for example, of a poorly structured fuel supply contract or a contract for transmission services that turns out to be uneconomic), the genco probably will walk. If the transco has an obligation to provide transmission service, the company might meet that obligation grudgingly.

There also is fear that the disco could become a weak market player, bypassed by its biggest customers and left serving only a market that is economically fragmented but politically very powerful (i.e., a market that uses its political power to keep rates low). In those circumstances, the disco may not have enough clout to insist that its suppliers maintain their plants even under adverse economic conditions.

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[73] U.S. Congress, Office of Technology Assessment, *Safe Skies for Tomorrow: Aviation Safety in a Competitive Environment*, OTA-SET-381 (Washington, DC: U.S. Government Printing Office, July 1988), p. 108.

Finally, the sort of industry structure envisioned in scenario 5 could result in a construction boom for new transmission with an associated increase in local siting battles.

Conclusions

Change is a given in the electric utility industry, and most observers would agree on the general direction of that change: toward greater competition in the generation sector and away from the traditional pattern of the vertically integrated electric utility. But as those changes appear, it will be important to keep an eye on the environmental impacts of the changed circumstances and conditions in the industry.

Neither expanded competition or increased transmission access is inherently incompatible with national environmental objectives. Nor are any of the scenarios inherently preferable on environmental grounds—at least, given our current level of understanding. However, as each scenario diverges further from the status quo than its predecessor, assessing environmental consequences become increasingly difficult and problematic.

In all cases, environmental concerns will be an important consideration in the policymaking that will accompany the changes in the electric utility industry. The OTA scenarios and other proposals would have their most direct environmental effects by affecting fuel choices and the generation mix, potentially frustrating achievement of anti-pollution goals and reducing incentives for development of some renewable energy technologies. Implementation of conservation and load management programs could be complicated and/or stalled by competitive markets that focus only on supply-side options. An increased demand for transmission services could lead to more transmission line construction and aggravate some already difficult disputes over transmission line siting. Based on OTA's preliminary review, there is little evidence that would support blanket assertions that major structural or regulatory changes in the electric power industry would be environmentally neutral or benign.

HEALTH EFFECTS OF POWER FREQUENCY FIELDS

For about two decades, there has been some concern about the health effects of electric and magnetic fields produced by electric power systems. Recent studies have only intensified this concern. One study in particular, the New York State Power Lines Report generated headlines in newspapers all over the world, focusing attention on the health effects associated with living next to power lines. Whatever the future direction of the electric power industry, these concerns are likely to persist.[74]

The first evidence that electric and magnetic power frequency fields might have a direct effect on human health appeared in 1972 when Soviet investigators reported that workers in Soviet extra high voltage (EHV) switchyards suffered from a number of ailments, such as appetite loss, fatigue, headaches, insomnia, and reduced sexual drive. While the Soviet research proved to have a number of flaws, it served to stimulate public concern.

In the United States, most of the health effects concerns have focused on fields generated by power lines. In several States, health effects have become a central issue in transmission line siting hearings. By the end of December 1987, there were about 144,386 miles of transmission line (230 kV and above) in the United States[75] and thousands of miles more under construction or being planned by utilities.

For many years, the scientific consensus was that power frequency fields could pose no threat to human health. Unlike x-rays that break chemical bonds by ionization, or microwaves that heat things up, power frequency fields are not powerful enough to break chemical bonds in human cells or cause significant tissue heating. Despite the low energy level of power frequency fields, laboratory research over the last 15 years has shown that even power frequency fields of low intensity (or strength) can disrupt certain processes at the cellular level.

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[74] Much of the information in this section is drawn from an OTA contractor report, by Indira Nair, M. Granger Morgan, and H. Keith Florig, Carnegie-Mellon University, Department of Engineering and Public Policy, "Power-Frequency Electric and Magnetic Fields—Exposure, Effects, Research, and Regulation," Jan. 16, 1989.

[75] NERC, *1988 Electricity Supply and Demand for 1988-1997*, October 1988, p. 63.

The research results are complex and often inconclusive. There have been many experiments that have found no difference between biological systems that have been exposed to fields and those that have not. But the growing number of positive findings have now clearly demonstrated that under certain circumstances, even relatively weak fields can produce changes at the cell level. Moreover, the number and consistency of positive findings has resulted in better experimental design and improved control of the experimental process.

As recently as a few years ago, scientists were making categorical statements that on the basis of all available evidence there are no health hazards from human exposure to power frequency fields. It is still not possible to demonstrate that such effects do exist, and it is important to remember that they may not. However, the emerging evidence no longer allows one to categorically assert that there are no risks.

If fields do turn out to be a health risk, it is unlikely that high-voltage transmission lines are the only sources of concern. Power frequency fields are also produced by distribution lines, household wiring, appliances, and lighting fixtures. These non-transmission sources are much more common than transmission lines and could play a far greater role in any public health problem.

There is, of course, no difference in the biological effects of exposure to power frequency fields under any of the scenarios discussed in chapter 3 or elsewhere in the report. Expansion of transmission systems in a manner that exposes more humans to potential hazards from electric and magnetic fields could occur under any scenario.

Sources and Nature of Electric and Magnetic Fields

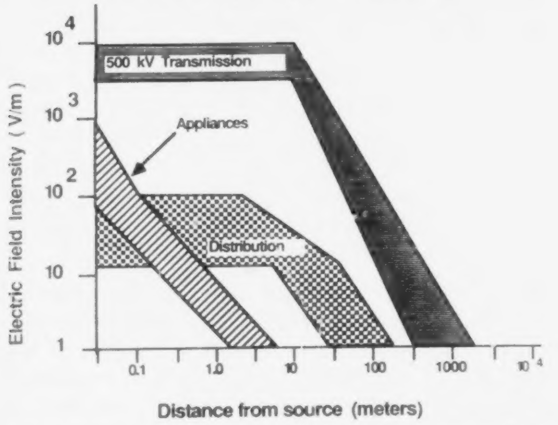
People are exposed daily to electric and magnetic fields. In fact, electric and magnetic fields arise from many natural sources. Processes in the atmosphere produce large static electric fields at the surface of the Earth, thunder clouds produce lightning, and the Earth's core produces a magnetic field which makes navigation by compass possible. Electric and magnetic fields are also produced by high-voltage transmission lines, low-voltage distribution lines, building wiring, electric appliances, and light fixtures. This section focuses on the fields created by power lines.

Power lines carry electric currents that alternate at a frequency of 60 cycles per second (60 Hz). That is, the current changes direction 60 times per second. The alternating current produces electric and magnetic fields around the power lines. These electric and magnetic fields, which oscillate at the same frequency as the electricity in the lines, are called power frequency fields. Power frequency electric and magnetic fields are "extremely low frequency" (ELF) fields. Other common electric and magnetic fields produced by radio and television broadcasting stations, for example, have higher frequencies than power frequency fields.

The term "*electric field*" is merely a description of the electric force that a charged object is capable of exerting on other charges in its vicinity. The intensity of the electric field is proportional to the magnitude of its force. The electric fields of power lines, wall wiring, and appliances are produced by electrical charges that are "pumped" onto the wires by electrical generators. Similarly, "*magnetic field*" is the term used to describe the magnetic force. The magnitude of the magnetic fields around a current-carrying wire is proportional to the amount of current. Both electric and magnetic fields have magnitude and direction. The electric field is measured in volts per meter (V/m) and the magnetic field in ampere per meter, gauss, or tesla.

Unlike ionizing and microwave radiation, which are forms of energy that travel distances from the source, ELF fields diminish rapidly with distance away from the source. Figures 7-2 and 7-3 show the intensity-distance relationship for fields produced by EHV transmission lines. Fields produced by power lines are strongest right under the conductors. The magnetic fields around many appliances are stronger than those under either a transmission or distribution line. However, magnetic fields produced by appliances typically fall off faster with distance than do fields from other sources. This is because appliances are less extended in space than are long power lines.

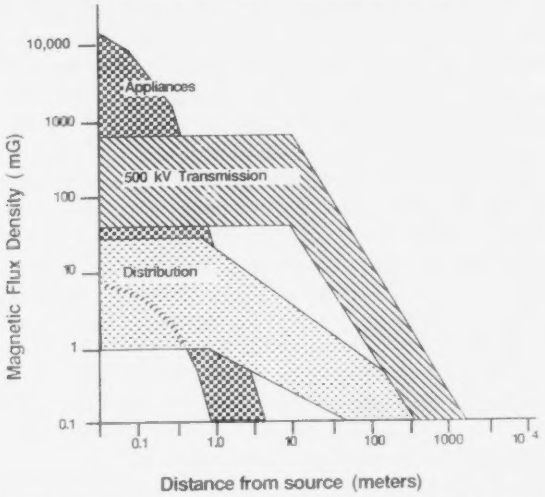
Figure 7-2—Electric Field Intensity at Ground Level v. Horizontal Distance From Three Common Sources of Power Frequency Electric Fields



Bands represent variation across individual sources in each group.

SOURCE: Adapted from H.K. Florig, I. Nair, and M.G. Morgan, *Briefing Paper 1: Sources and Dosimetry of Power Frequency Fields*, Technical Report, prepared for the Florida Department of Environmental Regulation under DER Contract SP117, March 1987.

Figure 7-3—Magnetic Field Intensity at Ground Level v. Horizontal Distance From Three Common Sources of Power Frequency Magnetic Fields



Bands represent variation across individual sources in each group.

SOURCE: Adapted from H.K. Florig, I. Nair, and M.G. Morgan, *Briefing Paper 1: Sources and Dosimetry of Power Frequency Fields*, Technical Report, prepared for the Florida Department of Environmental Regulation under DER Contract SP117, March 1987.

Shielding

Buildings and other large structures, fences, and vegetation can provide appreciable shielding from electric fields. Houses, for instance, diminish electric fields from nearby power lines by about 90 percent.[76] Also, electric fields can virtually be eliminated by grounded shield wires or screens in direct contact with the earth. Buried power lines produce almost no electric fields above ground.

Unlike electric fields, magnetic fields easily pass through most objects, including buildings, earth, and people. Houses, trees, and most other objects do not provide appreciable shielding from magnetic fields. Only structures containing large amounts of ferrous or special metals can shield magnetic fields.

Some have suggested that in the future, superconducting materials could be used to reduce exposures to power frequency fields.[77] In theory, superconducting materials could be used to carry large quantities of power as direct current thus avoiding the magnetic fields caused by rapidly alternating current. But they would not eliminate all magnetic fields—a static magnetic field would remain around the superconducting line because all currents produce a magnetic field in their vicinity. Moreover, use of superconductors could be prohibitively expensive or unnecessary for this purpose.

How We Are Exposed To Power Frequency Fields

The human body contains free electric charges, largely in ion-rich fluids such as blood and lymph. (There are also charges, although not entirely free, on cell membranes.) The electric charges, within the body, move in response to forces exerted by charges and currents on appliances and nearby power lines. The processes that produce these movements, or body currents, are called *electric* and *magnetic induction*.

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[76] H.K. Florig, "Population Exposure to Power-Frequency Fields—Concepts, Components, and Control," Ph.D. Thesis, Department of Engineering and Public Policy, Carnegie-Mellon University, 1986.

[77] *Superconductivity Flash Report*, "Do Overhead Transmission Line Health Risks Help SC," p. 8.

Electric Induction—In electric induction, charges on a power line or appliance attract or repel the body's free charges. Since body fluids are such good conductors of electricity, charges in the body move to the surface under the influence of this electric force. For example, a positively charged overhead transmission line induces negative charges to flow to the surface of the upper part of the body. Because power line charges alternate from positive to negative many times each second, the charges induced on the body surface alternate as well. Negative charges induced on the upper part of the body one instant flow into the lower part of the body the next instant. Therefore, power-frequency electric fields induce currents in the body as well as charges on its surface. Figure 7-4 shows electric and magnetic field strengths observed in common exposure settings.

Magnetic Induction—Magnetic fields are interrelated with electric fields. As noted earlier, alternating current produces magnetic fields which oscillate with the current. The changing or alternating magnetic fields, in turn, produce electric fields, which exert forces on the electrical charges contained in the body. This process is called magnetic induction. The currents induced in the body by magnetic fields are greatest near the periphery of the body and smallest at the center of the body. Because magnetic fields have only recently become a human health concern, data on the detailed distribution of magnetically induced currents in humans and animals are quite sparse compared to the information available on electric induction.

The magnitude of surface charges and internal body currents induced by power-frequency fields depends on many factors. These include the magnitude of the charges and currents in the source, the distance of the body from the source, the presence of other objects that might shield or concentrate the field, and body posture, shape, and orientation. Consequently, induced surface charges and currents are very different for different animals.

Contact Currents—In addition to electric and magnetic induction, humans are exposed to contact currents. Contact currents are the currents that flow into the body when physical contact is made between the body and a conducting object carrying an induced voltage. Examples of contact current exposure include contacts with the handle of a refrigerator and with vehicles parked under a transmission line. Contact currents often produce high current densities in the tissue near the point of contact. Although contact currents result in some of the most intense exposures, they are also among the briefest, usually lasting only as long as it takes to open the door of a car or refrigerator.

If a person touches a vehicle parked under a power line, the body provides a path to the ground through which the charge induced on the vehicle by the power line's electric field can flow. The magnitude of the contact current depends on a number of factors: local field intensity, the size and shape of the contacted object, and how well-grounded the contacted object and the person are. The largest contact currents are drawn by well-grounded persons who touch large metal objects that are well-insulated from the ground. Most common contact currents are imperceptible. Under the right circumstances, however, contact currents can be annoying or even painful. To protect the public from life-threatening contact currents, the American National Standards Institute (ANSI) has recommended that overhead lines be designed so that contact currents from even very large vehicles do not exceed 5 milliamps.[78] (One milliamp is equal to one-thousandth of an amp.) There is some concern that the ANSI limit is too high because 5 milliamps is still above the "let-go" threshold for some children. The "let-go" threshold is the current above which a person loses voluntary muscle control and cannot "let go" of a gripped contact.

Exposure Parameters

While it is possible to measure fields and induced currents to which people are exposed, scientists do not know which, if any, aspect of the field can have an impact on human health. For example, scientists do not know whether to be concerned about field strength, change in field strength over time, currents induced in the body, exposure duration, or some other variable. For most known potential hazards,

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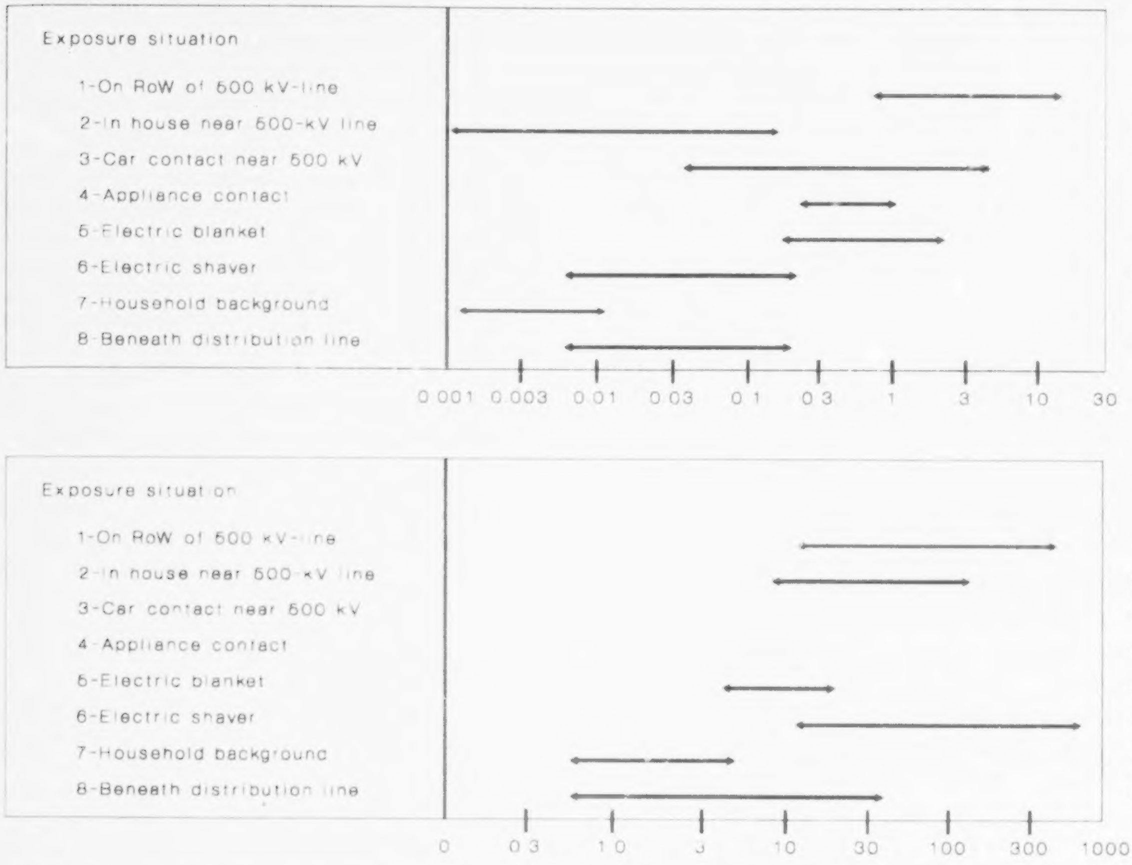
[78] American National Standards Institute, *National Electrical Safety Codes*, 1977.

Figure 7-4—Comparison of Ranges of Electric and Magnetic Fields From Common Power Frequency Sources



SOURCE: OTA adapted from Indira Nair, M. Granger Morgan, and H. Keith Florig, Power Frequency Electric and Magnetic Fields—Effects, Research and Regulation, OTA contractor report, Carnegie Mellon University, Department of Engineering and Public Policy, final report, Jan. 16, 1989.

such as chemicals, one can safely assume that if some of the agent is bad, more of it is worse. This may not be the case with power frequency fields. Biological experimental evidence about power frequency fields suggests that the "more-is-worse" assumption cannot always be justified.

Some suggested measures of the bioeffects of power frequency fields include:

- Frequency and intensity "windows"—biological effects are noted in specific narrow ranges of field intensity and frequency.
- Time thresholds—biological effects are observed only after several weeks of exposures.
- Time "windows"—biological effects are noted after long- and short-duration exposure periods. In some studies of cells and tissues, the effect is not observed immediately after exposure. Rather, there appears to be a window in time in which biochemical perturbation occurs.
- Field threshold—biological effects appear only when field strength exceeds some threshold value.

Together these different measures of dose suggest that one cannot make the assumption that dose is proportional to field strength or to time spent in the field.

Comparing Human Exposures From Different Sources

Because scientists do not know what measure is relevant in determining biological effect, comparisons cannot be made on the basis of relative contributions to effective dose. Comparisons among sources can be based only on those physical quantities that are amenable to measurement or theoretical estimates. These include electric quantities, such as induced surface charge and internal currents, exposure duration, frequency of exposure, and number of people exposed. Although the electric quantities may not relate in any simple way to a public health impact of a given source, scientists can use them to get some idea of how similar or different people's exposures from various sources are.

Current Scientific Evidence on Biological Effects of Power Frequency Fields

Most of what we know today about the effects of exposure to power frequency fields comes from three types of studies or experiments:

1. Laboratory experiments that use animal or human tissues or cell cultures exposed to fields. These experiments are termed "in vitro" (in glass).
2. Laboratory and field experiments that use animals exposed to fields. These experiments are termed "in vivo" (in live state) experiments.
3. Epidemiological studies that observe the effects of field exposures on human populations at work (occupational studies) or at home (residential studies).

Cell-Level Experiments

A considerable body of evidence has emerged that points to the cell membrane (the membrane enveloping the cell) as the primary site of interaction between ELF fields and the cell.[79] The cell's membrane serves as the boundary and maintains the structural integrity of the cell. It is also responsible for transmitting information arriving at its surface to the cell interior so that appropriate life processes can take place. The cell membrane is a highly selective filter that maintains an unequal concentration of ions (charged atoms) on either side and allows nutrients to enter and waste products to leave the cell.

The ELF experiments on the cellular level concentrated on how some of the specific processes governed by the membrane change as a result of exposure. Some of the changes noted in the experiments include the modulation of calcium ion flows; interference with DNA (deoxyribonucleic acid) synthesis and RNA (ribonucleic acid) transcription; interaction with the response of normal cells to hormones and neurotransmitters; and interaction with the biochemical kinetics of cancer cells.

The phenomenon most studied on the cellular level is the flow of calcium ions across the cell membrane when exposed to 60 Hz fields. Calcium is present in the membrane structure and is released when triggered by an appropriate signal. Calcium flow regulates physiological processes such as muscle contraction, egg fertilization, and cell division. The quantity and the rate of calcium ion transport are important in this regulation. When information in the form of an electrical or chemical impulse arrives at the cell membrane, the membrane binding and the permeability of calcium are altered and calcium is released. The subsequent flow of calcium across the membrane transfers information to the interior of the cell. In addition to regulating physiological processes, calcium flows activate certain enzymes called protein kinases, which are found on the surface of nerve cells. When activated by the calcium changes, these enzymes cause actions on other cell surface proteins that are important in cell adhesion during development and growth. The unusual behavior of calcium flow from cell membranes in brain tissue in vitro was the first clear, reproducible effect of ELF fields observed in biological tissue.

Recent research has demonstrated unequivocally that under certain circumstances, the membranes of cells are sensitive to externally imposed low-frequency electromagnetic fields, even when the fields' intensity is much weaker than the cell membrane's natural fields.[80] Consequently, processes that are governed by the cell membrane, such as a cell's capacity to recognize other cells, may be candidates for disruption by field exposure.

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[79] W.R. Adey, "Electromagnetic Fields, Cell Membrane Amplification, and Cancer Promotion," paper presented at the National Council on Radiation Protection and Measurements Annual Meeting, National Academy of Sciences, Washington, DC, 1986.

Also, ELF experiments have focused on chromosomal damage and interference with DNA synthesis and RNA transcription. DNA and RNA are the primary biomolecules in the cell. Nuclear DNA carries the genetic code while the extranuclear RNA transcribes the DNA command codes into proteins for the physiological functioning of the cell. Well-studied cancer-initiating agents, such as ionizing radiation and chemicals, cause direct damage to DNA by mutations. As noted earlier, ELF fields do not have enough energy to break bonds or otherwise disrupt the structure of DNA. However, research has shown that exposure to fields may interfere with the transcription patterns of RNA, resulting in the production of structurally changed proteins. Protein synthesis is a very complicated process, and experiments yield no simple interpretation about potential ELF effects on the organism.

Several experiments have studied the effects of ELF fields on endocrine tissue. From these experiments, it is impossible to draw any inference about the effects of fields on the endocrine system in a human or animal, other than to say that fields do exert an action on endocrine tissue and endocrine processes in vitro, and these effects, too, show windows.

Also, ELF experiments on interaction with the immune response of cells showed that field exposure had no significant effects on immunological functions of normal or specifically immunized cells. However, fields may affect cells already stimulated by mutagens (agents that provoke an immune response).

Several experiments have examined the effect of ELF fields on cancer cells. One of the hypotheses developed is that fields promote cancer formation or cancer growth rather than initiate cancer. The fact that ELF fields have not been known to cause alterations in DNA structure, as discussed earlier, is consistent with the observation that ELF fields do not initiate cancer. However, it should be noted that any potential relationship between field intensity and the degree of promotion may be highly complex.

It is important to remember that even when effects are demonstrated consistently on the cellular level in laboratory experiments, it is difficult to predict whether and how they will affect the whole organism. Processes in the cell are integrated through complex mechanisms in the animal. When a cellular process is perturbed by an external agent, such as an ELF field, other processes may compensate for the perturbation so that there is no overall disturbance to the organism.

Another problem in deducing possible health concerns from cell-level effects has been the lack of a theoretical model to explain and understand these potential effects. Although great strides have been made in recent years, cell membrane biology is still in its infancy. Until recently, there was not enough understanding to even advance hypotheses about the potential mechanisms by which ELF fields may disturb healthy cell and organ functions. Hypotheses are now being advanced but are still at a speculative stage. Several decades of carefully designed experiments may be necessary before all the current pieces of evidence fall into place in a coherent framework.

Moreover, many of the lessons learned from environmental hazards, such as chemical agents (PCB, vinyl chloride, benzene, etc.), or physical agents (asbestos, ionizing radiation, etc.), cannot be applied to ELF fields. The cell-level effects produced by ELF fields are complex and dependent on a number of factors, such as frequency and field strength, time pattern of exposure to the field, and direction of the applied field. The effects also may depend upon whether the field is a simple alternating field or a pulsed field. Because of these complex dependencies, ELF fields appear to be an agent for which there is currently no known analog.

A summary of the results of a number of cell level experiments is shown in table 7-4.

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[80] W.R. Adey, "Tissue Interactions with Nonionizing Electromagnetic Fields," *Physiological Reviews*, vol. 61, pp. 435-514, 1981; Testimony presented to the U.S. House of Representatives, Subcommittee on Water and Power Resources, "Health Effects of Transmission Lines," Oct. 6, 1987; W.R. Adey and A.F. Lawrence (eds.), *Nonlinear Electrodynamics in Biological Systems* (New York, NY: Plenum Press, 1984).

Whole Animal Experiments

In addition to cell-level studies, whole animal experiments have been conducted. Animal systems have been examined under a range of electric and magnetic field intensities and for varied exposures and durations. The experiments involved many different subjects, including rats, mice, miniature swine, cows, guinea pigs, and chicken eggs.

Historically, animal experiments focused on general effects rather than on formulating and testing hypotheses. Very early experiments were riddled with problems of poor experimental design, leading to artifacts in results. Moreover, animal studies with statistically sufficient numbers are very expensive and time-consuming. In the past 15 years, the quality of health effects experiments has improved but has not yet reached the hypothesis testing stage. Epidemiological studies have focused on a search for cancer as the primary effect because of historical observation rather than because cancer is the most likely effect.

Whole animal and human experiments are reviewed under these categories of effects:

1. General effects, such as detection, avoidance, and behavior responses; development and learning of animals; and moods of humans.
2. Effects on externally measured physical parameters, such as growth, birthweight, respiration, heartbeat rate, and temperature rhythms.
3. Effects on specific biochemicals such as hormones that are responsible for maintenance, regulation, and control of general physiological and psychological functions; for response to environmental stressors; for growth and development; and, for triggering special responses such as sexual function, and fetal and newborn nourishment.
4. Effects on circadian rhythms of animals and humans.
5. Epidemiology of cancer, particularly leukemia and brain cancer.

Table 7-4—A Summary of Results of Cellular Level Experiments: Effects and Possible Significance

Experiment	Effects noted	Possible significance
Calcium efflux from cell membrane (6 experiments)	Efflux is dramatically changed The change occurs only at some frequency and intensity values, but not at others.	Significance is not clear but points up the possibility that effects of fields may not be such that "higher field intensity is worse than lower."
Chromosomal damage (3 experiments)	No chromosomal damage detectable.	Does not cause the damage that usually initiates cancer.
DNA synthesis rate (1 experiment)	Rate change at low magnetic field.	Extremely low AC magnetic fields as small as the Earth's natural DC field may affect cell process rates.
RNA transcription (1 experiment)	New proteins made by the cell. Rate of transcription altered.	Fields may alter rates of primary cell processes.
Cell response modifications: Response to: A: hormones (1 experiment)	Modifications in adrenal and bone tissue response to hormones.	Public health significance not clear. Adrenal response shows intensity windows. Bone tissue experiment points to membrane as site pf action
B: Neurotransmitters (1 experiment)	Phase shifts in the periodicity of secretion rhythms.	If true in humans, could have implication for psychological disorders, such as chronic depression
C: Immune system (5 experiments)	Not clear that there are significant effects except in special cases.	Implications not clear.

SOURCE: I. Nair et al., Department of Engineering and Public Policy, Carnegie Mellon University, OTA contractor report, "Power Frequency Electric and Magnetic Fields: Exposure, Effects, Research, and Regulation," Jan. 16, 1989.

A summary of the results of whole animal and human experiments follows.

Detection, Behavior, Learning, and Avoidance Responses in Animals—No general conclusions could be gleaned from the experiments on general effects except to note that there are central nervous system effects which may be windowed even in the whole animal.

Reproduction, Growth, and Development— Reproduction, growth, and development studies measure a wide range of factors, such as reproductive behavior, prenatal viability; alterations in physical parameters, gross malformations, and central nervous system development. Most of the studies attempting to examine developmental effects of ELF field exposure have concluded that no overt defects and malformations resulted from the exposure. However, some studies have seen subtle effects and the possibility of the existence of an effect remains an open question.

Several studies have examined the effects of 60 Hz fields on bone growth and repair. Overall, these studies showed that high-intensity electric fields do not appear to have a strong effect on bone growth and repair in rodents.

Central Nervous System Effects—Animal studies have indicated that ELF-central nervous system interactions are very complex. Interactions may vary with the background static fields present, the time of day, and exposure duration. Studies have found that developing nervous systems may be particularly susceptible, and effects may be latent, manifested only in specific situations or later in time. Also, findings show that ELF fields are specific with respect to regions of brain tissue affected. Whether these findings have public health implications remains unclear.

Blood and Immune System Chemistry—The experiments conducted on blood and immune system chemistry imply that there is no general or overall immune system performance changes or short-term endocrine system changes induced by exposure to electric fields of a rather high intensity over a duration of several months.

Circadian Systems of Animals and Humans— The circadian timing system serves to synchronize various physiological and biochemical processes that have a daily cycle. Many aspects of the biology of circadian and other timing systems are not yet well understood. But, the last two decades have brought considerable understanding of some of the elements of the system. ELF experiments on the effects of electric and magnetic fields on circadian systems of man, primates, and lower animals indicate a definite effect on the periodicity of physiological functioning. It is not clear, however, whether such effects are deleterious or even long-lasting. Dyssynchrony of the circadian system has been associated with physiological and psychological disorders. These disorders include altered sensitivity to drugs and toxins and internal conflicts between the timing of physiological processes of sleep, and psychiatric disorders, including chronic depression.

Epidemiological Studies

Epidemiological studies have focused on the association between exposure to ELF fields and cancer in children and/or occupational cancer. These studies have received the most attention in terms of the public health consequences of exposure to ELF fields. Because ELF fields are not known to cause chromosomal damage, cancer promotion, as opposed to initiation, is most often cited as the role ELF fields play in carcinogenesis. However, no experiment or theory clearly proves that ELF fields promote cancer or growth enhancement.

Exposure to ELF fields was first linked to cancer by Wertheimer and Leeper in 1979. The authors estimated the comparative magnitude of the magnetic field in the home by the surrogate measure of wiring configurations. This landmark epidemiological study noted an association between childhood cancer and homes that were classified as located near "high current configuration" distribution lines that were likely to produce stronger than average magnetic fields. In 1982, the cancer association issue resurfaced again—this time in the workplace. The New England Journal of Medicine published an article on the effects of occupational exposure to 60 Hz fields. The article noted that power station operators had 2.5 times the death rate from leukemia. In addition, recent epidemiological studies have begun to examine the incidence of certain cancers to magnetic fields in the household environment. These studies have created a growing need to understand the various sources of magnetic fields in the home, which include not only appliances and house wiring, but also ground currents in plumbing, gas lines, and steel girders.[81] The latest and by far the most thorough study was funded by the New York State Power Lines Project.

Childhood Cancer—Five completed epidemiological studies have addressed the question of association between exposure to ELF fields and childhood cancer. Three of the five studies found positive results. (See table 7-5.)

The latest study, the New York State Power Lines Project, expanded on the 1979 Wertheimer and Leeper study, which involved children from the Denver area. Both wire coding and actual measurement of fields in homes were used to characterize the residential field environment. An analysis of the total childhood cancers occurring in the Denver area was also done and showed that Denver children share the same overall risk as those in the National Cancer Institute Surveillance, Epidemiology, and End Results (SEER) Program. The study also assessed other measures of potential field exposures, such as electric heat and hot water use, the use of heating pads and electric blankets by children and pregnant women, and the total number of electric appliances in the house. The general findings of the study follow:

- A 30-percent increase in risk (odds ratio = 1.31) for all cancers was observed at high magnetic fields (2.50+ milliGauss). The odds ratio did not systematically increase or decrease with field magnitudes, i.e., higher field ranges did not always give a higher cancer risk.
- Cancer subgroups were analyzed under the categories: leukemia, lymphoma, brain tumors, soft tumors, and "other cancers." All the categories except leukemia showed odds ratios of 1.3 to 1.6 at high (2.5 mG+) field exposures only. Leukemia showed an odds ratio of 2.11 for the highest field class and 1.23 for the 1.00 to 2.49-mG field range.
- The risk of cancer was not associated with magnetic field values at residence of birth.
- Higher electric fields did not show higher risk of cancer.
- Results on the relationship of childhood cancer to use of appliances, electric blankets, heated water beds, and electric heat are mixed but suggestive of a few trends. Electric blanket and isolette exposures were associated with increased risk of all cancers, especially of the brain and soft tissue, for isolette exposure.

Residential Exposure and Adult Cancer—Three studies have examined the association between adult cancer and exposure to ELF fields from nonoccupational sources. Wertheimer and Leeper were the first to report an association between adult cancers and residential wiring configurations. Four categories of wiring configurations were used to characterize residences in which subjects had lived for periods from 3 to 10 years prior to the diagnosis of cancer. The researchers found an association between cancers of the nervous system, uterus, and breast with a systematically increasing risk for higher current configurations.

The latest study carried out under the New York State Power Lines Project found no association between acute nonlymphocytic leukemia and residential wiring configuration and residential field exposure. The studies do not provide enough evidence that residential field exposure increases the risk of cancer.

Occupational Exposure and Adult Cancer—About 20 studies have examined the association between cancer, particularly leukemia and brain cancer, and occupational exposure to ELF fields. Studies have been done using electrical worker populations or ham radio operators in the United States, England, Sweden, and New Zealand. The results of all studies taken together indicate a small positive association or no association.

Leukemia—Occupational studies of the association of ELF exposure and leukemia show that electrical equipment assemblers and aluminum workers have the highest relative risk of all "electrical" occupations. Uncertainties about the relative risk of these two occupations, however, do exist. For example, job classifications do not clearly indicate actual occupational exposure to fields, and the studies did not take into consideration confounding

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[81] D.A. Savitz, *Case Control Study of Childhood Cancer and Exposure to Electromagnetic Fields*, Technical Report to the New York State Power Lines Project (Albany, NY: Health Research, Inc., 1987).

Table 7-5—Methodology and Results of Epidemiologic Studies of Childhood Cancer and Electromagnetic Field Exposure

	Wertheimer & Leeper (1979)	Fulton et al. (1980)	Myers et al. (1985)	Tomenius (1986)
Geographic source	Colorado	Rhode Island	Yorkshire (England) Health District	Stockholm County
Case group:				
Time period	Deceased 1950-73	Onset 1964-78	Diagnosed 1970-79	Registered 1958-73
Diseases	All cancers	Leukemias	All cancers	All tumors
Age range	0 to 18	0 to 20	0 to 14	0 to 18
Size	344 (491 dwellings)	119 (200 dwellings)	376	716 (1,172 dwellings)
Other criteria	Colorado birth certificates; resided in Denver area, 1946-73	Identified at Rhode Island Hospital; residences up to years before diagnosis	—	Born and diagnosed in Stockholm County
Control group:				
Source	Birth certificates	Birth certificates	Birth certificates	Birth certificates
Matching	Year of birth; some by county	Year of birth	Time of birth, near case's birth address	Age, sex, and church district
Size	344 (472 dwellings)	240 (240 dwellings)	501	716 (1,015 dwellings)
Other criteria	Subsets formed based on residence information	Only birth addresses considered	Only birth addresses considered	Birth and "diagnosis" address in Stockholm
Exposure:				
Definition	Wiring configurations (wire type, gauge, number, proximity to home)	Estimated exposure from Colorado measurements, divided into quartiles	Calculated magnetic fields from overhead lines	Electrical construction within 150 miles, including 200-kV lines; 50-Hz magnetic fields near door
Range	Up to 35 mG	NA	0.002 to 16.8 mG	0.004 to 19 mG
Potential confounders	Age of onset; sex; urban-suburban residence; socioeconomic class; maternal age; birth order; traffic density	Year of birth; father's socioeconomic level; age of onset	Age	Age, sex, church district
Results:	Positive association between high-current configuratidns and cancer; dose-response gradient, consistent across cancers	No association observed between imputed exposure and leukemia	No consistent tendency for higher exposures among cases	More electrical construction within 150 miles of case homes; more case homes >3 mG

SOURCE: I. Nair et al., Department of Engineering and Public Policy, Carnegie Mellon University, OTA contractor report, "Power-frequency Electric and Magnetic Fields: Exposure, Effect, Research, and Regulation," Jan. 16, 1989.

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variables and household and other exposures. Studies show that the third highest relative risk group—telegraph, radio, and radar operators, consistently exhibit increased risk. The largest set of data is available for this group.

Collectively, the studies do not provide sufficient evidence that work-related exposures to power-frequency electric and magnetic fields increases the risk of leukemia or brain cancer. However, there is sufficient evidence to warrant more detailed and finely focused research on this question.

Brain and Central Nervous System Tumor—The association between brain and central nervous system tumors and ELF field exposure related to occupation has been examined in a number of studies, some of which are general cancer studies. Brain cancer in adults is rare (1 percent of all cancer incidence; 5 in 100,000 risk), peaking at about 60 years of age. In comparison, brain cancer is the second highest risk cancer for children between 0 to 8 years of age.

The small number of occurrences of brain cancers in adults poses a data problem in establishing causal association. Also, the brain is a favored site for metastasis.[82] Therefore, cases counted as primary brain cancer may actually be secondaries spreading from a different organ where the cancer actually initiated.

In addition to the data problem mentioned above, the studies used occupational classification-based data to estimate exposure. Data are classified by job titles or general occupation codes, such as "electrical occupations." The problem arises when a general occupation code includes workers who are no more exposed to ELF fields than the average individual. For example, in some cases "electrical occupations" include electrical and telecommunications engineers. Even electricians often work with circuits turned off so that their exposures may not be significantly higher than those not in the electrical field.

Major Programs and Funding Levels for Health Effects Research

Over the years, funding for research on the effects of power frequency fields has fluctuated. Current levels of support are only modest. Over the past decade, the Department of Energy (DOE) has been the chief source of Federal funding. DOE's fiscal year 1988 budget for ELF research was $2.2 million, a substantial decrease from a high of $4.7 million in fiscal year 1985. The proposed budget for fiscal year 1989 is higher at $3.0 million.[83] The Bonneville Power Authority (BPA), a Federal power marketing agency, also has supported research. In the past decade, BPA has provided about $200,000 per year, primarily for environmental and livestock studies. A history of the research funding provided by the six largest programs is shown in figure 7-5.

The U.S. Navy played an important and early role in research on the effects of exposure to ELF electric and magnetic fields. In 1968, the Navy proposed to build an ELF submarine communications facility in northern Wisconsin that would have covered many thousands of square miles. In response to concerns raised by people in Wisconsin and to comply with the recently enacted National Environmental Policy Act, the Navy launched a large laboratory research program that examined the effects of ELF exposures on many animal and plant species.[84] Between 1969 and 1977, the Navy funded about 8 million dollars' worth of research. It now has two operating ELF transmitting facilities, one in Wisconsin and one in Michigan. The Navy has continued to sponsor ecological field studies in the vicinity of these transmitters. Navy funding for this program is currently about $2 million per year.[85]

At one time, several laboratories of the Environmental Protection Agency (EPA) had small research programs involved in both exposure and effects-related studies. Because of recent budgetary pressures, EPA's work on ELF fields has essentially stopped.[86]

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[82] Metastasis refers to secondary growth of cancer that spreads from a primary site.

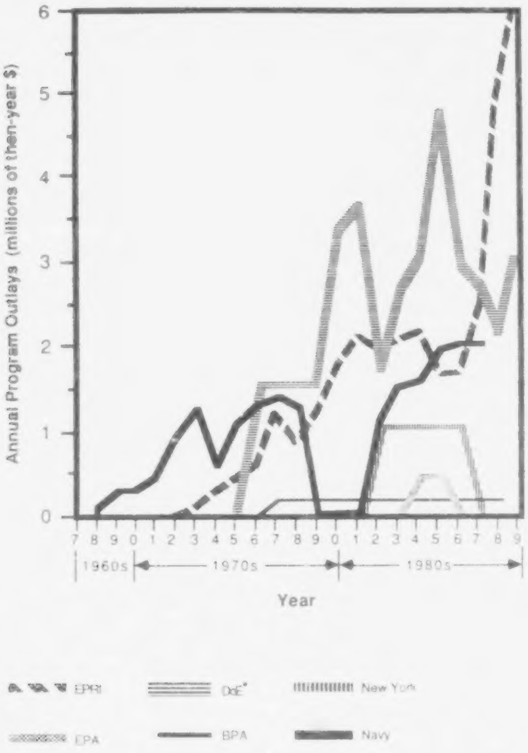
[83] I. Gyuk, U.S. Department of Energy, Washington, DC, personal communication, Nov. 22, 1988.

[84] T.C. Rozzell, "Biological Research for Extremely Low Frequency Communications Systems," *Biologic and Clinical Effects of Low-Frequency Magnetic and Electric Fields* (Springfield, IL: Charles C. Thomas, 1974), ch. 7, pp. 91-97.

[85] M.M. Abromavage, ITT Research Institute, personal communication, October 1987.

[86] Bioelectromagnetics Society, "Bioelectromagnetics Funding Survey," *Bioelectromagnetics Society Newsletter*, May/June 1986.

Figure 7-5—History of Funding for ELF Bioeffects Studies in the United States From 1986 to the Present



SOURCES: M.M. Abromavage, Engineering Advisor, IIT Research Institute, Washington, DC, personal communication, October 1987; Bioelectromagnetics Society, Bioelectromagnetics Funding Survey, *Bioelectromagnetics Society Newsletter* (68), May/June 1986; I. Gyuk, U.S. Department of Energy, Washington, DC, personal communication, December 1988; "DOE EMF Bioeffects Budget Set at $3 Million," *Microwave News* 8(5):8, September/October 1988; and S. Sussman, Manager, Non Ionizing Radiation Subprogram, Environment Division, Electric Power Research Institute, Palo Alto, CA, personal communication, December 1988.

State agencies have also funded research. From 1982 to 1986, the State of New York operated a $5 million research project on field effects. The project—the New York State Power Lines Project—was administered by the New York Department of Public Health, with m[illegible]y provided largely by the State's electric utilit[illegible] another useful but smaller State-funded program is the Maryland Power Plant Siting Program, which has supported database development and dosimetric studies at the Johns Hopkins Applied Physics Laboratory. In addition, the California Public Utilities Commission with assistance from the Department of Health Services (DHS) is currently reviewing and summarizing electric and magnetic fields research and related biological theories. DHS expects a report to be issued in September 1989. After the report is released and data gaps identified, DHS will launch a 3-year, $2-million electric and magnetic fields research program, which will be funded by a one-time utility tax.[87]

In addition to Federal and State Governments' support, the electric utility industry has been involved in supporting research on ELF fields effects. Utility support began as early as 1962 when the American Electric Power Company (AEP) funded two small-scale studies at Johns Hopkins University. One study focused on EHV lineworkers and the other on mice exposed to strong electric fields. AEP, several years earlier, had become the first U.S. utility to build an EHV transmission line. Several other utilities, most notably Southern California Edison, have initiated fields research programs. Together, utility sources have provided about $3 million in funding over the last decade.

The Electric Power Research Institute (EPRI), the utility industry's research arm, has spent $15 million on such research over the past decade and has increased its support annually. EPRI's 1989 budget targets about $5.5 million on electric and magnetic fields research.[88] The Institute is currently sponsoring ELF research on statistical studies of human disease patterns, measurements of actual human exposure, and laboratory studies on animals and cells.[89]

International Programs

Many nations have active fields research programs. These include Sweden, West Germany, United Kingdom, Canada, Japan, Italy, France, Finland, and Norway.

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[87] Personal communication with Dr. Raymond Neutra, Chief Epidemiological Studies Section, California Department of Health Services, Mar. 14, 1989.

[88] Dr. Robert Black, EPRI, personal communication, Nov. 30, 1988.

[89] *EPRI 1987 Annual Report*, "Technological Innovations: Window to Economic Prosperity," p. 16.

Sweden's research program has a budget of $1.9 million (11 million krona). Health officials have already embarked on a large-scale epidemiological study of people who have developed certain types of cancer and who lived within 300 meters of a 220- or 400-kV power line for at least 1 year between 1960 and 1983. Funding is provided primarily by Sweden's State Power Board and Sweden's National Institute of Occupational Health. Studies have focused on epidemiology, exposure assessment, and cancer induction and promotion.[90]

In the past decade, the United Kingdom has spent about $6 million investigating the biological effects from its high-voltage overhead transmission grid. After a decline in funding over the past few years, Britain's Central Electricity Generating Board (CEGB) now plans to double its research budget. This increase in funding was prompted by findings of the New York State Power Lines project. British scientists expect to spend about $2 million this year. The CEGB plans to measure the domestic exposure of every child who has contracted cancer in Britain in the past year or two. British research will use a range of new instrumentation that will permit precise measurement of electric and magnetic exposure and will deal with a domestic technology that differs significantly from the United States system. Where the United Kingdom differs from the United States is that far more of the local distribution system is buried instead of dangling from poles. Underground cables are twisted together in a way that tends to cancel out their fields. In addition to dose measurements, CEGB scientists will commission medical surveys from university statisticians to correlate with the measurements.[91]

The West Germans are currently funding a half-dozen projects that include animal teratology experiments, in vitro studies, and measurements of human exposure. Financial support is provided by both public and private sources.

Canadian utilities, Ontario Hydro and Hydro Quebec, have been actively involved in exposure-related research for some time and have recently begun an animal cancer study. They also have active programs in high-voltage DC field and ion effects. Japanese utilities have underwritten a number of studies of electric field dosimetry over the last few years and funded a study at Southwest Research Institute on the effects of electric fields on baboon behavior. Italy's programs are entirely utility funded and include electric field studies with chickens and rodents.

Strategies for Research

At the same time as scientific developments have prompted many to conclude that the issue of possible 60 Hz health risks should be taken seriously, there has been a marked decrease in the level of Federal funding for ELF effects research. The reductions in funding do not, however, appear to be a deliberate effort to reduce fields research but rather a byproduct of efforts to limit the level of overall Federal expenditures.

While current research is sufficient to raise serious concerns about ELF field health effects, it is not sufficient to provide satisfactory answers or to point the way to action. Without adequate research on which to base answers, the vigorous public debate on ELF health effects, and in some instances intervention and litigation, could go on for many years and have costs significantly greater than the costs of the needed research.

Beyond the issue of funding levels, several research management issues need to be examined when addressing the potential health effects of ELF fields. An overall ELF research program should include a balanced mix of cell-level, whole animal, and epidemiological studies. No one study is likely to lead to the kind of complete understanding that is necessary to make informed judgments about risk assessment and management. While epidemiological studies may be able to establish an association between health impacts and humans, cell and animal studies would have to demonstrate the mechanisms, and other features, of the effects. The identification of dose-response mechanisms is essential for the development of effective risk management strategies.

Also, there is a danger of becoming too focused on cancer promotion as a single health effect of concern. The breadth of cell-level and animal experiments suggest that other public health effects deserve some attention.

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[90] *Technology Review*, "Power Lines and Cancer: The Evidence Is Growing," October 1987.

[91] David Fishlock, "Britain Will Double Its Budget for Research Into Electromagnetic Fields," *Energy Daily*, vol. 16, No. 61, Mar. 30, 1988, p. 3.

Furthermore, little attention has been given to field exposures that result from sources other than high-voltage transmission lines. As noted earlier, fields from distribution lines, building wiring, and appliances could be primary sources of public health effects. It will be important for legislators, regulators, and others to address the issue as one of field exposure rather than as a problem of high-voltage transmission lines. Otherwise, enormous attention may be devoted to one, possibly minor, source of public exposure while ignoring other, possibly major, sources of public exposure. A systematic characterization of the entire low-frequency field environment to which people are exposed in normal modern life would be useful to this end.

Finally, little or no research has been done on exploring techniques for reducing or eliminating 60 Hz field exposures. Preliminary work conducted by Carnegie-Mellon University suggests that in many cases solutions may be possible at economically reasonable levels. For example, a low-field electric blanket might be designed by using concentric conductors in the heating elements, by using twisted pair heating elements, or by using heating fluid. A series of carefully conducted studies designed to explore the technical and economic feasibility of reducing field exposure, is needed.

ELF Exposure and Regulatory Activity

In recent years, States have experienced increasing pressure to take regulatory action to protect citizens against the possible hazards posed by power frequency fields. Major transmission line projects in New York, Montana, and Florida, for example, have encountered considerable public opposition based in part on concerns over possible health effects. In several instances citizens have carried these disputes into the courts. In response to these pressures, States have taken a number of approaches to regulate exposures to electric and magnetic fields.

By January 1989, seven States had already set limits on the intensity of electric fields around power lines. A brief summary of the existing field limits is shown in table 7-6.

Officials in Florida have adopted standards to limit the amount of both electric and magnetic fields that new power lines generate. Florida is the first State to restrict magnetic fields around transmission lines. The final maximum edge of right-of-way magnetic field strength limits for new transmission lines are 200 mG for 500-kV lines, 250 mG for double-circuit 500-kV lines, and 150 mG for 230-kV and smaller lines.[92]

Starting in July 1988, Ohio utilities applying for approval of a new transmission line must first submit calculations of electromagnetic field strength of the proposed line. Predicted field strengths must be made for the edge of the right-of-way for the line and at the fence line for substations. However, according to the Ohio Power Siting Board, not much will be done with the calculations until a national consensus is formed.[93]

To date, most of the pressures are directed toward the control of transmission lines. It is likely that similar pressures will increase for distribution lines—at least for those lines that are visible. On the other hand, pressures to control fields associated with building wiring and appliances are likely to increase more slowly.

Legislators and regulators have been dealing with known or suspected health risks from environmental agents for decades. However, data on exposure to ELF fields is even more complex and uncertain than evidence compiled for other hazards such as toxic chemicals and ionizing radiation. Because of the complexity of the interactions between power frequency fields and living cells, conventional legislative and regulatory strategies that focus on setting "safe" or "acceptable" exposure thresholds may not lead to effective results for the possible risks. The experimental evidence that finds a windowing of observable effects and the presence of effects at very low-field strengths makes reliance on conventional threshold approaches probably inappropriate and unsupportable by available scientific data.

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[92] "Florida Environmental Regulators Set New Electromagnetic Field Limits," *Electric Utility Week*, Jan. 30, 1989, pp. 1-3.

[93] "For New LInes, Ohio Utilities Told to Submit Data on Field Strengths," *Electric Utility Week*, May 23, 1988, pp. 19-20.

Table 7-6—State Regulations That Limit Field Strengths on Transmission Line Rights-of-Way (RoW)

State	Field limit
Montana	1 kV/m at edge of RoW in residential areas
Minnesota	8 kV/m maximum in RoW
New Jersey	3 kV/m at edge of RoW
New York	1.6 kV/m at edge of RoW
North Dakota	9 kV/m maximum in RoW
Oregon	9 kV/m maximum in RoW
	10 kV/m maximum for 500-kV lines
	2 kV/m maximum for 500-kV lines at edge of RoW
	8 kV/m maximum for 230-kV and smaller lines in RoW
	2 kV/m maximum for 230-kV and smaller lines at edge of RoW
Florida	200 mG for 500-kV lines at edge of RoW
	250 mG for double circuit 500-kV lines at edge of RoW
	150 mG for 230-kV and smaller lines at edge of RoW

SOURCE: I. Nair et al., Department of Engineering and Public Policy, Carnegie Mellon University, OTA contractor report, "Power frequency Electric and Magnetic Fields: Exposure, Effects, Research, and Regulation, Jan. 16, 1989.

Three important limits need to be considered in policy choices. First and foremost, it has not been conclusively proven that ELF fields do pose a health hazard. Second, it is possible that no straightforward dose-response relationship exists between the degree of exposure and the level of harm, thus reducing the effectiveness of traditional standards approaches to risk management. Finally, there are many potential sources of ELF exposure and transmission and distribution lines may not in fact pose the greatest threats. In the future, better scientific understanding may clearly demonstrate the existence of adverse public health effects from ELF field exposure from transmission and distribution lines and suggest specific risk management strategies. But, for now, we have to operate with admittedly imperfect response strategies. Possible policy responses include the following:

- Deferring regulatory action while continuing and expanding research to resolve scientific uncertainties.
- Establishing public information programs.
- Adopting a field strength-limit approach to transmission line fields by setting an arbitrary "acceptable level of exposure" even though not fully supported by scientific evidence.
- Adopting a "similarity" based approach to transmission line fields designed to make people's exposures to transmission line fields as "similar" as possible to the exposures from all the other fields common in our daily lives.
- Adopting a "prudent avoidance" strategy by taking reasonable steps at modest costs to keep people out of fields in the siting and re-routing of transmission and distribution lines and by redesigning electrical systems to reduce fields.

Chapter 8

Public Policy Issues and Legislative Strategies

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Chapter 8

Public Policy Issues and Legislative Strategies

This chapter provides a broad overview of a number of the public policy issues and potential legislative responses associated with creating a more competitive electric power industry. The policy options in this chapter are aimed at the general technical and institutional changes that may be required to expand competition among potential suppliers of electric power, including increasing access to transmission services, and not at the direct implementation of the scenarios used in OTA's analysis.

This policy discussion targets three areas of potential congressional concern. The first area includes the key technical and institutional changes that must occur to assure that the reliability and economy of operation of the bulk power systems do not suffer in any competitive transition. The chief responsibility for assuring their successful implementation will rest on the electric power industry, including new competitive generators. While regulators and legislators will be directly involved in the initial decisions on what competitive changes will be adopted, they have only an indirect role in implementation and system operations. Nevertheless, there are a range of actions that can be taken to encourage a smooth transition.

The second area of concern embraces the broad public policy questions that will be central to any debate over fundamental changes in the regulation of electric utilities and bulk power markets:

- encouraging broader market participation,
- expanding transmission access,
- changing existing Federal laws and regulations, and
- establishing an appropriate balance in Federal and State regulation of electric power.

A range of alternative legislative strategies are identified for each.

The third area of congressional concern is the lack of information, analysis, and experience to support decisionmaking about electric power industry structure and regulation. Notable areas where additional research and information are needed are bulk power markets, transmission system capabilities, the potential efficiency gains from expanded competition, and the availability of other alternatives to achieve similar efficiency gains. Related areas that also merit further investigation are the impacts of competition on other Federal energy and environmental goals. Finally, we include some possible legislative responses to the possibility raised by recent scientific studies that exposure to power frequency fields may pose a human health hazard.

TECHNICAL CONSIDERATIONS—POLICY OPTIONS AND ISSUES

Enhancing and Preserving Reliability and Economy in a More Competitive Industry

A fundamental goal of the regulated electric power system has been to maintain reliability of the system while providing economical service. Any shift to a more competitive industry structure would not alter this goal, but its achievement would depend on successfully continuing coordinated planning and operation of the bulk power system.

The bulk power system consists of generation and transmission resources that are planned and operated together in a coordinated fashion. Currently most generation and transmission facilities are integrated either because they are both owned and controlled by the same vertically integrated utility or they are tied together through a local control area. Competitive trends are already modifying that traditional model. The system today already has absorbed a significant increase in bulk power transfers and the entry of nonutility generators—mostly qualified cogenerators and small power producers. The terms and conditions for the transactions that have driven these incremental changes were largely dictated by the integrated utilities and power pools. It is not at all clear, however, whether more extensive or rapid changes can be as easily accommodated and whether effective system operating arrangements will evolve to adequately protect reliability.

Increasing bulk supply competition and expanding transmission access will generally involve a separation or unbundling of the ownership and/or operation of generation and transmission facilities.

The extent could range from modest changes, as in scenarios 1 and 2, to more extensive long-term industry restructuring, as in scenarios 3, 4, and 5. As long as competitive generation[1] makes up only a small portion of the generating resources in an integrated system, most control and coordination problems posed by these alternative suppliers should not be serious and can be handled by available technologies and operating procedures. With more and more new utility and nonutility generators supplying bulk power to the system, however, the degree of separation in operation and ownership will grow and direct utility control could potentially decrease. As the portion of the generating base not directly under utility operation grows, maintaining effective coordination of planning and operations will become more complex, but not impossible. Similar difficulties arise as the number of wheeling transactions increase—because the bulk systems operations center has less direct control over the generators pushing power onto the lines. For the system to function reliably and effectively, some entity must coordinate the individual generation and transmission components. Under all scenarios, but especially scenarios 2 through 5, this may require additional agreements and operating guidelines, and in some instances, creation of new institutions and operating relationships that would include nonutility buyers and sellers in the cooperative efforts.

Meeting the Technical Requirements for a More Competitive Generating Sector

It is possible that as competition assumes a greater role in the generation sector the number and diversity of electric power producers will increase. With such a change would come greater technical and institutional challenges in meeting the three main requirements for coordinating the bulk power system:

1. adjusting generator output to follow load changes;
2. maintaining reliable operations; and
3. coordinating power transactions among interconnected systems.

Effective generation control and coordination for the expanded competitive system as a whole will be achieved through some combination of equipment and operating agreements, contractual obligations, and other subsidiary arrangements.

Generation Control for Load Following—Control centers and generators must establish operating agreements and maintain the equipment necessary to follow moment-to-moment fluctuations in load. This frequency regulation equipment includes the central automatic generation control systems, governors on the generators, and metering, communication, and accounting equipment to measure generator performance under an agreement to provide load following service. Responsibility for load following can be assigned in contracts and coordination agreements. For nondispatchable units, arrangements might be made to provide and compensate for these services by either reducing the amount paid to the generator or assessing a share of the associated system costs.

An integrated system also requires that generating units be scheduled to follow daily, weekly, and seasonal **load cycles**. A control center for an integrated utility or a tight power pool usually follows a previously established unit commitment schedule and ramps up or down the individual generating units as needed to follow actual or predicted loads. Schedules are usually set to achieve the best economic dispatch of available units. Because off-peak loads may be only 50 percent or less of peak loads, systems require a large fraction of schedulable generation to be able to follow daily, weekly, and seasonal load variations. Some units, such as nuclear plants and large fossil-fired steam turbines, are used to meet fairly constant or base loads and are considered "noncycling." A firm power sale committing the output of a specific generating unit to serve a specified wholesale or retail customer, which might be a typical bulk power transaction under a more openly competitive system, could be considered as a noncycling unit for load following.

As the amount of noncycling or nonscheduled generation in a system increases, both the difficulties of providing cyclical load following and the economic costs of doing so can increase. Potentially, the burdens of system support could fall heavily on the utility controlling the system and its generating units. Under a competitive system where generators are paid only for the electricity they generate, some mechanism must be in place to encourage competitive suppliers to follow load cycles since it may require operating their facilities below capacity. This will require the negotiation of specific agreements for dispatch and scheduling control for load following, the establishment of compensation schemes or preferences for load following competitive suppliers, and the assessment of load cycling system charges for nonparticipating generators.

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[1] By "competitive generation" we mean bulk power obtained through a competitive procurement process from a generator that is not owned and operated directly by the purchasing utility. The supplier could be another utility (or a subsidiary or affiliate), a PURPA qualified facility, or an independent power producer.

Generation Control and Reliability—Control over generation is also needed to schedule and control power flows between interconnected systems. This is essential to minimize the potential for unintended power exchanges on transmission lines between systems.

All interconnected generating units must be under some coordinated control for security in case of emergencies. The type of control required to prevent bulk system failures is more immediate than that used for load following. Agreements are also needed to resolve system engineering problems and to maintain system operations within stability limits.

Maintaining spinning reserves and "ready reserves"[2] as substitute power supplies in case of emergencies is necessary for system reliability and security. To meet this obligation the system maintains generating units that are operating or standing by to provide needed power on short notice. In a competitive generating sector, the costs and responsibilities for maintaining system reserves may need to be reallocated.

Legislative and Regulatory Initiatives—The responsibility for establishing an adequate technical framework to support a more competitive generating sector will largely fall on the electric utilities, the competitive generators, and the industry's various voluntary and professional associations. And a successful transition will depend on their cooperative efforts. There are, however, a few areas where Federal and State legislators and regulators can further the technical and institutional changes needed to assure adequate system coordination. The first area for possible government action is improving information gathering and research to support a competitive industry structure. A few State regulatory agencies and utilities are already jointly pursuing these changes. They are still a minority, however.

Although there already has been some experience with integrating competitive supplies into utility systems, most of these transactions have been on a small scale. Unbundling generation and bulk power system support functions will require development of new standards, data collection practices, and analytical methods that are acceptable to all or most participants. Much can be done using existing technology and methods and adapting them to a new operating environment. Perhaps the primary areas where additional information and research are needed to establish a firm technical foundation for a more competitive electric generation sector are: a) coordinated operations, and b) coordinated planning.

Most utilities support integrated system operations by allowing their generating units to be dispatched to follow loads and maintain reliability. In a more competitive bulk power market, not all generators may be willing or able to follow loads. This could result in an unbundling of generation functions and of the responsibilities for providing them. This raises issues of how to maintain coordination and how to apportion system support cost equitably. If competitive generators agree to allow their plants to be dispatched and/or scheduled cyclically, the control center will need detailed cost and operating information for the units. Appropriate contractual agreements or guidelines will need to be devised to assure compliance with load following responsibilities and to require information sharing. New and better means of calculating a precise value for load following and cycling services will need to be developed either to compensate load following generators or to establish a preference in bidding systems. An acceptable method will also be needed for determining the costs of and setting prices for providing load following services through scheduling or full dispatchability.

Among the possible policy initiatives available to assure that the industry adequately anticipates and meets the technical and institutional challenges of a changing bulk power system are the following:

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[2] Ready reserves include generating units and interruptible loads that can be dispatched within 10 minutes.

- Regulatory agencies could establish guidelines for determining and allocating the costs of providing unbundled services, such as load following, and the additional support services related to system reliability.
- Regulatory agencies and utilities could work together to establish minimum or standard bulk power purchase agreements that provide for the necessary technical conditions of generation control, coordinated operations, and specific obligations for system support services and/or payments.[3] More flexible arrangements could also be negotiated, provided that adequate provisions were made to preserve reliability.
- Regulators may need to require that competitive supply contracts contain adequate enforcement and default terms to assure that power supplies will continue to be available. Alternatively, regulators may need to approve larger reserves for reliability and load following purposes, as well as possible increases in transmission system capacity.

As part of their obligation to serve, public utilities have the responsibility to plan for future power needs. This utility planning is often conducted with close review and oversight by State regulators and in cooperation with other utilities. Generation control and system engineering considerations are incorporated into these internal planning activities. Information about demand forecasts and resource plans are frequently shared among utilities through NERC regional and subregional councils and other voluntary associations to assure that individual utility resource plans are consistent with regional reliability guidelines.

Most of the current planning efforts rest on a model of an integrated utility meeting its own needs in cooperation with its neighboring systems. New planning methods may be required to integrate potential competitive power supplies in resource plans and operating guidelines and to accommodate new uncertainties that they may bring. New mechanisms or institutions may be needed to promote participation in cooperative planning by competing generators to assure that overall system operating standards are achieved.

- State regulators could require utilities to provide more detailed descriptions of system needs and technical requirements in filings with regulatory agencies or bulk power solicitations so that alternative suppliers could effectively compete to provide reliable service. This obligation would be imposed on integrated utilities and on transmission and distribution utilities under a restructured industry.
- Regulators might consider structuring the resource planning in a competitive system to facilitate and encourage long-term planning that allows more systematic choices about generation mix, type, location, environmental impacts, demand management, and conservation strategies.

Meeting the Technical Requirements for a More Open Transmission System

Under any approach to expanding access to transmission systems, the primary technical challenges will be in accommodating a greater diversity among generators and bulk power customers and in handling an increased number of wheeling transactions.

The transmission system is an integral component of the overall bulk power system, and it functions through the coordinated control and operation of generating units to move power within and between interconnected systems. Wheeling transactions require some entity to coordinate generation and reactive power sources to maintain voltage and frequency, minimize inadvertent flows over other systems, and provide for security and reliability. Expanding bulk power transfers also raises issues of how to schedule and allocate available transmission capacity, how to cost and price unbundled transmission system support services, and how to encourage construction of needed capacity. The technical challenges and the likely cost and reliability impacts of increased wheeling will depend strongly on who the buyers and sellers are, their mutual obligations, the type of service required, and the volume of transactions. It will also be important to include assessments of future transmission needs in overall system planning for generation and transmission resources.

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[3] Some State PURPA and competitive bidding programs already have some forms of standard contract terms. These standard arrangements could be expanded so that technical concerns are addressed more explicitly.

The major challenges in accommodating moderately expanded transmission access are primarily institutional, but overcoming these hurdles is central to its technical feasibility. Under most, if not all, scenarios for change, it will be necessary to create new methods and procedures of coordination, capacity allocation, accounting, and compensation for unbundled transmission services. Increased wheeling transactions or a more open transmission system will create challenges for operation and planning and may require the establishment of new entities and working arrangements to take over some of the functions now performed by integrated utilities, power pools, and cooperative agreements among utilities.

Expanding transmission services also involves some technical challenges. The reliable operation of the Nation's transmission systems requires coordinated control of most generators that are connected to the system. Coordination in a more competitive system with expanded wheeling would function essentially the same as in the existing system, but there would likely be many more transactions to execute. Under a competitive system, the responsibilities for providing certain system support functions might be shifted from integrated utilities to alternative generation suppliers. Control center operations and planning will become more complex.

There are significant technical differences between wheeling services required for a purchasing integrated utility with its own generation and wheeling services for a retail customer or requirements utility without its own generation. If the purchaser has its own generation, it generally has the ability to follow load and provide for reliability. If it does not, the wheeling customer will have to arrange for equivalent reliability protection with the wheeling utility or bulk power supplier.

Firm transmission agreements tying a specific generator to a specific customer could cause serious challenges for system operators in preserving reliability and economy. As the volume of such transactions increases, the restrictions they impose on economic dispatch and security constrained dispatch may result in additional costs and reserve requirements on the integrated system. Additional transmission and generating facilities may be needed for system reliability, which makes this problem similar to that presented in integrating nondispatchable generation.

An additional generation control problem that could increase with more wheeling is the need to provide frequency regulation for customers with no generators of their own. Integrated utilities now provide such services to their full requirements or distribution only utility customers. If expanded competition reduces the integrated nature of the electric power industry, more wholesale and retail customers could require frequency regulation services from one source but base load and cycling power from another.

The bulk power system infrastructure and operations will have to evolve to accommodate the changes that would arise under expanded transmission access. Control centers may need to be upgraded with more personnel and equipment to handle more transactions. New and improved software for control area operations and accounting will be needed to execute and track unbundled transactions.

Information and Research Needs—Laying the institutional and technical foundations to support greater levels of wheeling in a more competitive bulk power system will require new and different information, an increased sharing of information, and development of new and different ways of planning, operating, and administering the transmission systems. At the same time that unbundling creates a more urgent need for information sharing, competitive pressures to withhold timely information will also increase.

The development of acceptable and accurate estimates of transmission capacity and availability will be increasingly important in a competitive environment. There is also a need for more generally acceptable and understood methods for use in setting specific transmission system limitations. The analytical methods and standards in use today are largely the result of cooperative efforts by integrated utilities and rest heavily on complex system studies, professional judgments, and agreements among power system engineers. The criteria can vary from system to system and region to region. While these specially tailored standards reflect the complexity of local bulk power systems, they may make effective oversight of more flexible transmission pricing and denials of transmission access unworkably complex. Without a common and acceptable approach to questions of transmission availability and capability, it may prove exceedingly difficult for competitors and regulators to resolve transmission access disputes.

In order to be able to compete effectively in the marketplace, purchasers and suppliers will want to know when, where, and at what price they can move power. If a transmission entity claims that it lacks the capacity to accommodate a desired trade, that judgment could be challenged. Competitors and regulators will need more acceptable, objective standards for assessing transmission availability to assure that control over transmission systems is not being used to unfair competitive advantage and/or that transmission utilities are fulfilling their obligations to provide adequate capacity.

In addition, accurate and acceptable measures must be developed for determining the additional system costs that wheeling transactions impose on the primary parties involved and on other systems.

Legislative and Regulatory Initiatives—Most of the responsibility for assuring that the transmission system continues to function reliably in a more competitive structure will necessarily rest on the electric power industry. But legislators and regulators also have an important role to play because the provision of transmission services will remain a monopoly under virtually any credible industry structure. It is likely that growth of a more competitive generating sector will require much more vigorous regulation of transmission access and pricing than currently exercised by Federal and State regulators. The following are among the major areas where legislative and administrative actions will be required if it is decided to expand transmission access. Some activity in these areas is already ongoing but to a far lesser extent than actions on competitive supplies.

An effective regulatory framework will need to be established to oversee transmission arrangements and appropriate transmission pricing policies. Compensation policies could be developed for inadvertent flows and constraints imposed on other systems from wheeling transactions. To the extent that the existing system does not provide this guidance, this will likely require action at both the Federal and State levels.

Congress could require the Federal Energy Regulatory Commission to establish guidelines or rules for determining and allocating the costs of providing unbundled transmission services, including additional support services related to system reliability. (FERC could also move to establish these regulatory standards on its own initiative.)

State regulators could encourage or require integrated utilities to consider overall regional transmission capacity needs in their planning activities. The costs of providing all or part of an adequate transmission capacity could be included in the ratebase.

Congress could require a more detailed study of the technical and institutional changes required for successful transition to a more open transmission system under one or more preferred competitive systems. The study might be coordinated by FERC or the Secretary of Energy. (Such a study would be useful even if the policy choice is to expand opportunities for transmission access and to allow competition among generating sources to evolve slowly under existing law and regulation.)

Federal and State Governments could fund necessary studies for resolving common problems in establishing standards for transmission availability, in costing and pricing of transmission services, and in minimum contract provisions for wheeling services. Alternatively, Federal and State regulators could provide a forum for development of a consensus approach by regulators, utilities, nonutility generators, and bulk power customers.

Creating a Stronger and More Flexible Transmission Network To Accommodate Industry Change and National Needs

Many proposals for expanding competition either have assumed that adequate transmission capacity would be available to allow the growth of competitive markets or have ignored transmission capability issues. The existing transmission networks already support higher levels of bulk power transfers than just 10 years ago, according to industry experts. At times, during record-setting peak demands in the summer of 1988, transmission line constraints prevented power transfers to avoid voltage reductions and brownouts in New England. And although NERC reports that transmission capabilities are generally adequate for projected needs, its periodic reliability assessments note a number of key transmission constraints that it says could affect reliability and system security.[4]

Are the Nation's existing transmission systems and coordinated operations adequate to support expanded competition and increased wheeling? There is no clear answer to that question because of uncertainties over what forms increased competition will take and where and under what conditions additional wheeling will be needed. There is also a lack of consensus over standards for determining adequacy. In looking at the technical feasibility of increasing transmission access, OTA found that there is no independent and systematic review of existing transmission system constraints and bottlenecks. Some constraints identified by NERC and others are tied to transmission lines that are the subject of protracted regulatory or court proceedings. Others involve limitations on particular wheeling transactions, and still others reflect temporary conditions arising from the loss of specific lines or power plants or from particular bulk power flow patterns. Evidence supporting a contention that we are currently suffering a long-term physical transmission shortage is spotty and anecdotal. OTA's own survey of electric utilities elicited a few examples of transmission constraints, but according to the respondents, few were of sufficient magnitude to offset the costs of correcting them.

Assessing Transmission Capability: Legislative and Regulatory Strategies

In the absence of any systematic and credible assessment of the strength and flexibility of the Nation's transmission system to support the growth of competitive bulk power markets, specific recommendations for physical system improvements cannot be made. Concerted efforts by Federal and State Governments and the utility industry will be vital to securing an adequate appraisal of the capabilities of our interconnected transmission networks.

Better assessments of transmission capability could lead to greater consensus over corrective actions and additional capacity and how to pay for them. Better analysis is needed on the adequacy and availability of transmission capacity for transmission system planning and regulatory oversight. More information is needed and improved analytical methods must be devised to carry out this task, however. Data are needed both for individual utility systems and for the larger interconnected grids. There are several ways of addressing these information problems.

On a national level, it may be an appropriate time to commission a new detailed study of the capability of the Nation's transmission systems to serve projected needs and to respond to emergency situations. There have been at least two previous federally sponsored studies of the national power grids and it is generally agreed that the studies resulted in improved system operations.

There is a need for more frequent assessments of regional transmission capabilities and constraints to aid regulators, system planners, and transmission users. One approach is to continue relying on the transmission utilities and voluntary organizations, such as the North American Electric Reliability Council (NERC), to provide that information. This "voluntary" approach has at least several obvious disadvantages. First, their conclusions may be viewed with suspicion by regulators and competitors, particularly among independent power producers and public power agencies. Second, they may be unwilling to assume the increased responsibilities and risks for reporting and analysis without some regulatory concessions. Third, voluntary associations may lack the necessary authority to gain access to critical technical information or to share it with others. In a more diverse electric power industry, these organizations, which have traditionally been dominated by large integrated utilities, may need to expand to include wider participation in order to remain credible.

An alternative approach is to revise existing government reporting requirements at the State and Federal level to assure that sufficient information is obtained periodically to monitor the health of the transmission systems. It would be useful to involve the utilities, voluntary industry associations, energy planners, and regulators in identifying the necessary information and any additional reporting requirements.

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[4] See discussion in ch. 6 of this report.

Fundamental to the success of increased efforts to monitor the capability of transmission systems will be the development of standard methods for monitoring and measuring transmission capacity and availability. As noted above, despite their shortcomings, these standards are also needed for more effective transmission system oversight by regulators and could be developed through the regulatory process. Alternatively, government agencies could sponsor and participate in joint efforts with industry to develop appropriate technical guidelines to assess transmission capability under a competitive system.

In addition to improved reporting requirements, regulators may elect to require utilities to include more frequent and detailed assessments of their transmission systems with particular attention to analysis of potential physical improvements for increasing capacity or reducing bottlenecks and the costs and benefits of such actions. This transmission assessment could be included in system planning reports or in periodic reviews of utility operations and would be available to the public as well.

EXPANDING COMPETITION IN THE ELECTRIC POWER INDUSTRY—INSTITUTIONAL AND POLICY ISSUES

Enhancing Bulk Power Competition

There are four prerequisites for creating a more competitive generating sector. First, the existing regulatory and institutional structure must be altered either through evolution or by political decision to accommodate changes. Second, there must be a market opportunity as evidenced by an increased need for power, a potential for cheaper power, or a specialized niche such as that provided for qualified facilities (QFs) by the Public Utility Regulatory Policies Act (PURPA). Third, potential competitors must be able to enter the market to sell their services. Fourth, there must be a market—some mechanism to bring together buyers and sellers to make offers and acceptances and to transfer the commodities or services sold.

In previous sections, we addressed some of the technical and institutional changes necessary to establish a foundation for a more competitive bulk power industry. We suggested a number of possible legislative and administrative actions that could be taken to build that foundation. But proposals for changing the regulatory and institutional structure of the bulk power industry raise many other legislative issues. Under different strategies for expanding competition and different levels of competitive changes, congressional action will be required for successful implementation. Without congressional action, competition may be limited or lopsided and evolutionary changes may make traditional utility regulation impractical and/or ineffective in achieving Federal and State electricity policy goals. It is also possible that in the absence of an aggressive regulatory presence the growth of a competitive generation sector may be so extensive that Congress or regulators may need to slow the process to allow the regulated transmission and distribution sectors adequate time to adjust their own operations and procedures. In this and following sections we outline some of the legislative issues that are likely to arise under alternative paths of industry change.

Creating a More Competitive Market Structure Under Existing Laws

Market forces have already gained a significant foothold in the electric power industry as a result of economic pressures on utilities and their customers and the influence of PURPA. Within fairly broad boundaries, existing competitive trends and administrative proposals would allow both electric power regulation and the generating sector to evolve to include more opportunities for competition among suppliers and greater reliance on market-based rates for bulk power. If these changes are viewed as desirable, Congress might allow administrative efforts to continue, while monitoring the impacts of limited competition within a regulated industry.

The extent to which a more competitive market structure is likely to evolve will depend greatly on the related but separate issues of access to and pricing of transmission services. In addition, the Federal Power Act, PURPA, and the Public Utility Holding Company Act (PUHCA) limit regulators' exclusive reliance on competitively procured power costs in setting wholesale and retail rates and constrain broad participation in competitive power markets by some entities.

Congress could encourage further experimentation with more competitive markets and transmission access at the State level to gain additional information on possible savings and social costs and benefits. This might be achieved through congressional oversight of FERC and influence over the appropriations process.[5] It would of course be essential that the results of any such experiments be monitored closely and rigorously analyzed for them to provide any effective or credible guidance for further congressional and administrative actions to change electric power regulation and market structure.

FERC has proposed a shift toward greater reliance on market forces in regulation in its notices of proposed rulemaking (NOPRs) on competitive bidding for setting avoided cost capacity payments under PURPA and "relaxed regulation and flexible pricing for IPPs [independent power producers]" under the Federal Power Act. Some observers note that FERC also has attempted de facto deregulation of wholesale economy sales through its general "hands-off" approach to reviewing negotiated prices.

Prospects for the growth of an extensive competitive generating sector under FERC's proposed approach are somewhat uncertain because of existing statutory constraints on participation by utilities under PUHCA, the limited exemptions from Federal and State utility regulation under PURPA, and general uncertainties over future electric utility regulatory policies. Questions have also been raised as to whether FERC's initiatives may exceed its statutory authority. On the other hand, the experience with rapid growth in QFs under PURPA and the appearance of some IPPs indicates that the current system can support at least some increased level of competitive supplies.

Legislative Actions To Promote Broader Participation in a Competitive Generating Sector

If the growth of a competitive generating sector is consistent with other national goals in energy policy and utility regulation, Congress may wish to reconsider several existing legislative restrictions that may limit some potential participants in a competitive generating sector. By modifying or repealing provisions of the Federal Power Act, PURPA, and PUHCA, Congress could significantly expand the ranks of eligible competitors in the bulk power markets. However, changes in these laws would be highly controversial and could jeopardize other important public interests and national policies.

Moreover, it is not clear that such actions are necessary to draw new participants into the bulk power industry. Most of the restrictions in existing laws are not absolute barriers to participants who want to build generating plants and sell electric power. Nevertheless there are some critics who would like to see the laws changed to expand exemptions from Federal and State public utility regulation. Under current law, most generators who sell power are considered public utilities. As a result, a generator might:

1. be required to file extensive financial and cost information with Federal or State regulators,
2. be limited in its ability to sell electricity at market rather than cost-based prices,
3. be required to maintain a "balanced" capital structure, and
4. be restricted from engaging in extensive non-utility businesses.

Some industry observers in FERC and elsewhere believe that the threat of being treated as a public utility deters potential investors in competitive generation. Electric utilities are also somewhat constrained from competing to sell power in areas remote from their interconnected system areas by the limitations in PUHCA, either because their operations as registered holding companies are highly restricted, or they fear losing their exempt status.

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[5] It would also be possible for Congress to enact legislation providing a limited exemption from certain provisions of PUHCA and FPA, similar to those allowed under PURPA, to allow competitive market experiments to take place either for a limited duration or for specific classes of competitors. Congress could require that FERC closely monitor and report on any savings achieved, any additional system costs, and the effects on system operations and reliability.

PURPA offers a limited exemption from State and Federal public utility regulation, including PUHCA, to certain qualified facilities. These entities have been able to operate somewhat freely under the existing regulatory structure. Indeed, many utilities have joined the ranks of QFs through joint ventures with other parties to build and/or operate qualifying plants. Changes to the size, technology, and utility ownership restrictions for QF eligibility would be one way of expanding competition, however, this change could undercut a fundamental goal of PURPA to promote cogeneration, alternative energy technologies, and small power production.

On the other side, there are many utilities, State regulators, and consumer groups that would oppose any relaxation of laws governing public utilities either to attract new entrants to the industry or to ease the limitations on the competitive activities of regulated utilities. They argue that existing laws provide ample latitude for both utility and nonutility participation in competitive markets and that where certain activities may be constrained there may be important public policy considerations that would support maintaining the protections of existing laws, such as PUHCA.

Expanding Access to Transmission Services—Legislative Issues

A potentially significant mechanism for expanding competition in electric power generation would be to assure that potential competitors can gain access to needed transmission services at reasonable rates. Transmission access allows generators outside a host utility's territory to compete to provide electric power. As a prerequisite for expanding transmission access, there must be adequate transmission capacity available and arrangements to preserve system reliability.

Actions Under Existing Law—At present, most transmission access and wheeling arrangements are voluntarily negotiated between the power purchaser and the wheeling utility. FERC oversees the terms and conditions of transmission agreements. FERC has very limited authority to order a utility to provide transmission service or to build new lines, although many public power utilities argue that FERC has not used its existing authority aggressively enough. State authority is also believed to be limited. A range of approaches have been suggested to promote greater access to transmission services that do not require legislative changes. The following five approaches are representative.

One—Relying on voluntary arrangements and the growth of competitive bulk power markets to create sufficient economic incentives for transmission utilities to open up their grids to other competitive suppliers. This approach leaves existing provisions unaffected. There has been some movement in several regions towards providing greater access to transmission services, notably in the Northeast and the Pacific Coast. A major limitation in this approach is that utilities may be unwilling to provide wheeling services to allow their current wholesale and large retail customers to shop for power from alternative sources. Even where a refusal to wheel can be found to be an unlawful anticompetitive practice, reliance on traditional antitrust enforcement to provide an effective and timely remedy may be impractical. A further objection to the current system is the lack of any provision for compensation to other utilities for unintended flows over their lines from other bulk power transactions.

Two—Changing the administrative process and policies to encourage voluntary access by providing more public information on wheeling arrangements and rates, setting deadlines for negotiating wheeling requests, providing a mechanism for mediation of disputes over wheeling, and collecting more data on the costs of providing wheeling services so that they can be more fully reflected in rates. This approach is similar to the first in that it does not require a change in legislation and could be accomplished administratively. This approach also suffers many of the disadvantages of the first approach, but may offer some incentive to utilities who might otherwise be unwilling to provide services. The change in the process could also provide a more detailed evidentiary record to support antitrust actions in cases of refusals to wheel.

Three—Using transmission pricing incentives to encourage transmission utilities to provide services and expand capacity. Some industry analysts have asserted that voluntary access could be encouraged if regulators were to change transmission pricing from a strict embedded cost basis to other approaches, such as "flexible" pricing, that include additional economic incentives. Other analysts have suggested that improvements in cost-based transmission pricing would also be beneficial. FERC has approved several experimental transmission agreements with alternative pricing schedules.[6]

Four—Using existing authority to require access as a condition of participating in a competitive market. Because of Federal court decisions and various FERC decisions, the extent of FERC authority to require a utility to agree to provide transmission access as a condition for receiving favorable FERC action on the treatment of certain wholesale transactions is open to question. Some observers believe that FERC has such authority, while others do not. FERC has requested comment on this issue in its competitive bidding NOPR.

Five—Encouraging joint ownership and participation in transmission line construction and upgrades through conditioning authority, antitrust review, and authority over Federal power marketing agencies and cooperative loans, and Federal ownership and influence over rights-of-way. FERC and State agencies could encourage transmission utilities to allow participation in new transmission capacity by other utilities by conditioning approval of rates, transmission agreements, and other regulatory actions on such agreement by a petitioning utility. FERC has used its approval of Pacific Power & Light's acquisition of and merger with Utah Power & Light to expand access to the new utility's transmission lines under its authority to approve mergers under section 203 of the Federal Power Act.[7] Bonneville Power Authority has been pressured to expand access to its transmission capacity to regional utilities. Federal land agencies granting rights-of-way over public land might condition such grants on sharing of the transmission capacity under a policy to maximize joint use of right-of-way corridors.

Changes in Federal Law To Expand Transmission Access—If reliance on existing law and administrative action to provide transmission services proves unworkable, ineffective, or undesirable, Congress could take legislative action on transmission access issues. Perhaps the most direct approach would be to amend the Federal Power Act and PURPA to provide more effective wheeling authority for FERC, as outlined in the five following approaches.

One—Providing new Federal wheeling authority as a remedy for refusals to wheel. Because of restrictive statutory provisions and court decisions, FERC and others contend that it has little effective authority to order a utility to provide wheeling services after it has refused to wheel in an exercise of monopoly power to restrict competition. Congress could amend the Federal Power Act to provide explicit authorizations for such remedial wheeling orders and could also authorize FERC to order a utility to increase transmission capacity if needed to comply with a remedial order. In amending the Federal Power Act, Congress could make clear that the PURPA amendments did not restrict wheeling as a remedy to monopoly or anticompetitive abuses. This change could also be coupled with pricing changes to provide more adequate compensation for transmission services and procedural changes to shift the burden of proof to the party denying access. One possible alternative mentioned in our discussion of scenarios would be the option of transferring greater authority over instate wheeling, retail wheeling, and regional wheeling arrangements to State commissions.

Two—Providing Federal wheeling authority under a broad public interest standard. This approach, which forms the basis of the wheeling provisions in OTA's scenarios 2, 3, and 4, would allow FERC to order wheeling whenever it determined it was in the public interest. Essentially, this amendment would drop many of the restrictive conditions placed on mandatory wheeling authority under PURPA, especially the requirement that the order must not disturb existing competitive relationships. As an additional option, included in OTA scenario 2, wheeling orders for very large retail customers might also be allowed, perhaps with a requirement that appropriate State regulatory agencies be consulted about potential impacts on other wholesale and retail customers and State policies.

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[6] These include two bulk power marketing experiments: *Southwest Experiment*, FERC Opinion No. 203, Docket No. ER84-155-000, Dec. 30, 1983 (see box 5-E in ch. 5 of this report); and the Western Systems Power Pool, *Order Accepting Experimental Rates for Filing*, FERC Docket No. ER87-97-001, Mar. 12, 1987 (box 5-F in ch. 5). In 1988 FERC approved two transmission agreements with novel pricing schemes: *Pacific Gas & Electric*, FERC Docket No. ER88-219-000, Mar. 31, 1988, 42 F.E.R.C. 61,406, clarification issued June 1, 1988 (contract between PG&E and the Turlock Irrigation District); and *Pacific Gas & Electric*, FERC Docket No. ER88-302-001, July 5, 1988, 44 F.E.R.C. 61,010 (contract with the Modesto Irrigation District). The Turlock agreement is briefly discussed in ch. 5, box 5-G.

[7] There are already instances of joint ownership and operation of transmission by utilities in Georgia, Indiana, South Dakota, and Minnesota. For example, in Georgia, the statewide transmission grid is owned by a consortium of a private power company, municipal electric utilities, and rural electric cooperatives. Operating charges are assessed according to each group's use of the grid. Larry Hobart, American Public Power Association, personal communication, Nov. 21, 1988.

Three—Providing for Federal action to reduce monopoly power over transmission services. The Federal Power Act could be amended to provide that if FERC determines that a major utility controlling significant transmission systems in a region either exercises or has a substantial potential to exercise monopoly power over transmission to the detriment of other utilities or the public interest, the transmission utility may be ordered to open up a portion of its capacity as a common carrier to other regional utilities and to maintain adequate transmission capacity to serve regional needs. Such an action would be a dramatic expansion of the FERC action in the *Utah Power & Light* decision where it found that approval of the proposed merger would likely result in unlawful monopoly control over regional transmission services unless conditions requiring expanded access for other utilities were adopted.

Finally, two additional approaches to expand access to transmission services involve a more direct Federal role in encouraging capacity expansion through more cooperative State planning efforts and expansion of the Federal role in providing regional transmission services.

Four—Authorizing the creation of multi-State regional transmission planning compacts. Congress could enact legislation that would establish regional compacts to promote regional cooperation and planning for transmission capacity. This approach was suggested by the National Governors' Association and is based in part on the regional nuclear waste compacts and the legislation creating the Northwest Power Planning Council.[8]

The authority of the regional commissions would be limited to assessing and planning for transmission needs. They would not site, certify, or approve transmission lines. However, States could individually require that lines be consistent with regional needs as identified in the regional plan in order to be approved by State regulatory authorities. Similar conditions could be imposed on approval of federally owned transmission facilities and on the use of Federal lands for rights-of-way.

Five—Authorizing the creation of new federally authorized transmission entities to provide wheeling services. The Federal Power Marketing Agencies (FPMAs) currently exist to market and transmit power produced from federally financed power facilities of the Bureau of Reclamation and the Corps of Engineers. The regional agencies are authorized to build and operate transmission lines to move power to customers and to contract with private utilities for wheeling services. From time to time, it has been suggested that the power marketing agency concept be expanded to provide regional transmission services for public power agencies, consumer cooperatives, and other utilities. The new agencies could be either directly under Federal control or federally authorized multi-State regional commissions. Another possible structure is to create federally chartered private corporations to own and run the transmission systems. Under scenarios 4 and 5, which would result in dramatic restructuring of the industry, creation of publicly owned transmission entities would be one way of disaggregating the transmission sectors to provide coordinated transmission services.

Restoring a Balance in Federal and State Regulatory Jurisdiction— Legislative Issues

Current competitive trends in the electric power industry have served to increase the tension that has always existed between Federal and State regulatory jurisdictions. Federal court and agency decisions and changing industry practices have tilted the balance toward a more dominant Federal influence over wholesale, and thus retail, power prices perhaps to a degree not anticipated in PURPA or the Federal Power Act. This trend will accelerate under a competitive bulk power market structure unless Congress changes existing laws to limit or override Federal court and agency decisions.

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[8] National Governors' Association, *Moving Power: Flexibility for the Future*, Report of the Committee on Energy and Environment Task Force on Electricity Transmission, 1987.

Under the Federal Power Act, Federal regulation of interstate wholesale sales was seen as a necessary measure to fill a gap in State regulatory jurisdiction. With increasing interconnections among utilities, corporate restructuring, and an expansive interpretation of the jurisdictional provisions of the Federal Power Act, virtually all wholesale power sales involving privately owned utilities, except for those in Alaska, Hawaii, and parts of Texas, come under exclusive FERC jurisdiction. The same is true for transmission agreements, including those between utilities that are in the same State and otherwise subject to State jurisdiction.

Restoring State Primacy to Utility Regulation

If Congress wanted to reform Federal utility regulation to restore and strengthen the traditional model of State regulated utilities within a limited Federal system, possible legislative actions might include:

1. Limiting the application and/or extension of the *Mississippi Power* case on preemption of any inquiry into prudence of wholesale sales at the State level. This would allow State regulators to examine and rule on the reasonableness of wholesale power contracts by State jurisdictional utilities.[9]
2. Amending the Federal Power Act to return jurisdiction over most instate wholesale power and wheeling transactions to State authorities. This would in effect be accomplished by a legislative override of the *Colton* case preempting State jurisdiction over instate wheeling and power sales.[10]
3. Requiring FERC to defer to State agency decisions in matters that historically have been governed by State law, such as prudence and resource planning. Congress could require that FERC defer to prior State decisions on approved utility resource plans and the prudence of wholesale power purchase arrangements and to consult with State regulators on such matters in any FERC rate proceeding.
4. Modifying the Federal Power Act to provide that the creation of a utility holding company consisting of separate, but formerly integrated, generation, transmission, and distribution companies would not create a wholesale relationship subjecting transactions among these entities to exclusive Federal jurisdiction. This would limit the ability of utilities to escape State oversight by forming holding companies or generation subsidiaries to sell power to retail distribution subsidiaries that are either directly or indirectly controlled by the same parent corporation.
5. Amending the Federal Power Act to provide State regulators with access to interstate holding company books and records needed for State oversight and requiring FERC to cooperate in obtaining and sharing the information needed. This might include a FERC inquiry as to whether it collects adequate and appropriate information to oversee the utility industry. Closing this information gap for State regulators would allow more effective State oversight of multi-State transactions. States could certify to FERC their need for obtaining information from companies selling or transmitting power operating in interstate commerce.
6. Providing for a State role in any new Federal wheeling authority. FERC might be required to notify and consult with State regulators on wheeling petitions on such local matters as the potential impacts on native utilities and ratepayers or the desirability of retail wheeling.

Creating an Expanded Federal Role in Utility Regulation

If on the other hand, Congress concludes that a primary Federal role over wholesale sales is appropriate and that most State regulatory inquiries should effectively be preempted, it may want to consider whether FERC authority or procedures should be modified to provide equivalent protections for consumers, wholesale customers, and State and local governments that have commonly been available in many States.

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[9] *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, No. 86-1970, June 24, 1988. For suggestions by one State regulator on possible changes to Federal laws to give States a more effective role in regulating more competitive bulk power markets, see "Testimony of the Honorable Ashley C. Brown, Commissioner, Ohio Public Utilities Commission" in Oversight Hearing on Independent Power Producers and the Public Utility Holding Company Act Before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, 100th Cong., 2d sess., Sept. 14, 1988.

[10] *Federal Power Commission v. Southern California Edison Co.*, also known as *City of Colton v. Southern California Edison Co.*, 376 U.S. 205 (1968).

Alternatives to Competition for Achieving Reliability and Economy

Generation competition and expanded transmission access are but two reforms that have been urged as a means of making the electric power industry more economically efficient and providing lowest cost power to retail customers. Congress and other policymakers may want to investigate the extent to which other changes in the industry could yield many of the same benefits without requiring significant and possibly irreversible institutional changes. Examples include:

1. Promoting greater cooperation and more effective use of utility resources through expansion of power pools and coordination arrangements with increased use of central dispatch and interconnection agreements.
2. Encouraging experiments in facilitating economy bulk power markets such as the Western Systems Power Pool and the Florida Power Broker.
3. Allowing continuation of the trend toward consolidation of regulated private utilities with close Federal and State oversight and appropriate conditions to prevent growth of monopoly abuse particularly in the area of transmission.

Impacts on Other Public Policy Goals

Changes in the electric power industry structure could have consequences in other public policy areas such as environmental regulation, consumer protection, and energy policy. Among the specific policy areas that might be affected by legislative and regulatory changes to promote creation of a more competitive electric power industry include:

- conservation and least cost management programs of utilities and State regulatory agencies;
- PURPA incentives for cogeneration and alternative electric power technologies, including whether required QF purchases at avoided cost continue to be effective in meeting PURPA's energy policy goals;
- consumer representation and access to information for retail rate hearings at the State and Federal level;
- the effectiveness of current regulations in achieving environmental protection goals such as permitting standards for new electric plants, fuel mix, and plant repowering, and shifts in environmental impacts of power generation among regions and technologies; and
- energy R&D programs including impacts on industry funded efforts and on the viability of Federal incentive programs from a more competitively constrained and disaggregated industry.

These areas deserve particular oversight to ensure that the indirect impacts of expanding competition are as constructive as possible.

Better Information and Analysis for Public Decisionmaking

OTA found a notable lack of accurate and relevant information and analysis on many aspects of both existing bulk power transactions and competitive markets. The areas where improved information and analysis would be beneficial for policymakers include:

- information on patterns of bulk power trades and wheeling transactions (e.g., how much power is bought, sold, and wheeled, where, when, and at what prices);
- more accurate and complete information on the emerging competitive generating sector including nonutility generators (QFs and IPPs) and self-generators, (e.g., location, size, ownership, dispatchability, operating status, contract terms, and problems encountered);
- more analysis and identification of actual potential efficiency gains from competition; and
- more analysis of opportunities for and potential benefits of bulk power transactions.

To address this lack of information and analysis, Congress could require the Energy Information Administration and FERC to review existing data collection, analysis, and reporting activities and to report to Congress on: 1) proposals to revise or expand existing activities to provide more adequate coverage of electric power industry data and trends, and 2) recommendations for expanded data collection and reporting authority to cover any gaps in existing law or regulation.

Power Frequency Fields and Public Health

It now seems possible, based on the state of scientific research, that exposure to electric and magnetic fields, such as those produced by electric power systems, could pose a hazard to human health. While it is not yet possible to demonstrate that such hazards do in fact exist, and they may not, it is no longer possible based on emerging scientific evidence to assert categorically that they do not. The research results are complex and inconclusive. Nevertheless, concern is growing among policymakers and people living near existing or proposed transmission lines.

Power frequency fields from high voltage AC transmission and distribution lines are but one source of exposure. Electric blankets, household appliances, lighting fixtures, and inside wiring also create low-frequency electric and magnetic fields. These sources are far more common than transmission lines and may play a far more significant role in human health.

Policymakers are faced on the one hand with the possibility that people are being exposed to previously unrecognized hazards, and on the other with potentially unnecessary costs and delays in transmission construction. These uncertainties will persist under any strategy for expanded competition. Among the possible actions that Congress might consider are:

1. Funding additional research on potential health effects (including reexamination of research priorities in Federal military and civilian programs on biological effects) and on methods of shielding humans from exposure to electric and magnetic fields from powerlines, building wiring, electric equipment, and appliances.
2. Funding research necessary to determine the possible extent of health problems (e.g., actual field strength and exposure measurements, population studies, epidemiological studies).
3. Funding research into methods for establishing exposure guidelines for use in siting or relocating transmission lines to avoid exposure where it can be done prudently and without excessive cost.

Appendixes

Appendix A
List of Acronyms and Terms

Acronyms

AC: alternating current
ACE: area control error
AGC: automatic generation control
ANSI: American National Standards Institute
CWIP: Construction Work in Progress
DC: direct current
DOE: Department of Energy
DSG: dispersed source of generation
ECAR: East Central Area Reliability Coordination Agreement
ECC: energy control center
EHV: extra high voltage
ELF: extremely low frequency
EMS: energy management system
ERCOT: Electric Reliability Council of Texas
FERC: Federal Energy Regulatory Commission
FPA: Federal Power Act
HVDC: High voltage direct current
IPP: Independent power producer
kV: 1,000 volts (kilovolt)
kW: 1,000 watts (kilowatt)
kWh: kilowatthour
LOLP: loss of load probability
MAAC: Mid-Atlantic Area Council
MAIN: Mid-American Interconnected Network
MAPP: Mid-Continent Area Power Pool
MW: 1 million watts (megawatt)
NARUC: National Association of Regulatory Utility Commissioners
NEPA: National Environmental Policy Act of 1969
NEPOOL: New England Power Pool
NERC: North American Electric Reliability Council
NOPR: notice of proposed rulemaking
NRC: Nuclear Regulatory Commission
PJM: Pennsylvania/New Jersey/Maryland Interconnection
NPCC: Northeast Power Coordinating Council
NUG: nonutility generation
PSD: prevention of significant deterioration
PUC: public utility commission
PUHCA: Public Utility Holding Company Act of 1935
PURPA: Public Utility Regulatory Policies Act of 1978
QF: qualifying facility
SCADA: supervisory control and data acquisition
SERC: Southeastern Electric Reliability Council
SPP: Southwest Power Pool
VAR: volt-amps-reactive
V/m: volts per meter
WSCC: Western Systems Coordinating Council

Terms

Alternating Current (AC): Electric current that reverses direction many times per second (120 times per second in the United States); almost the entire U.S. power system uses AC except for some long-distance direct current (DC) transmission lines.

Automatic Generation Control (AGC): A system used to control the output of electric generators in a control area to balance the supply and demand of power and execute power transactions with neighboring control areas.

Bulk Power System: Includes generating units, transmission lines, and related equipment.

Capacity Margin: The difference between generation capacity and peak load expressed as a percentage of capacity.

Circuit: A conductor or system of conductors that forms a closed loop through which current flows.

Cogeneration: Production of both electrical (or mechanical) energy and thermal energy from the same primary energy source.

Conductors: Bundled strands of wire that carry electric current.

Control Area: A region with an energy control center responsible for operating the power system within that area.

Coordinating Transactions: Involves the scheduling and control of generation to implement power transfers, as well as monitoring and recording the transactions for billing or for other compensation.

Direct Current (DC): Electric current that flows continuously in one direction.

Distribution lines: Power lines delivering electricity to customers at relatively low voltages typically between 110 and 69,000 volts.

Economic Dispatch: A system for selecting generating units to operate to balance supply and demand at minimum cost.

Economy Transfers: Power purchased by one system from another because it is less expensive than power produced by the first system's own generating facilities.

Electric Field: The electric force that a charged object is capable of exerting on other charges in its vicinity.

Hertz (Hz): Frequency measured in cycles per second; power systems in the United States operate at 60 Hz.

Load Management: The manipulation of customer demand by economic and/or technical means.

Loop Flows: Parallel path flows crossing utilities' boundaries along paths not contracted for or scheduled.

Loss of Load Probability (LOLP): A measure of the long-term expectation that a utility will be unable to meet customer demand.

Magnetic Field: The magnetic force that a charged object is capable of exerting on other charges in its vicinity.

Qualifying Facility (QF): Generating unit qualifying for special regulatory treatment under the Public Utility Regulatory Policies Act of 1978.

Radial or Feeder lines: Transmission lines connected to the grid at only one end; the other end is connected either to a power plant or distribution system.

Ramp Rate: The rate at which a generator's power output can change.

Reactance: A phenomenon of AC power in which the voltage and current are out of phase, that is, they do not peak simultaneously.

Reactive Power: Power which is stored by reactive elements in a power system; called VARs (Volt-Amps-Reactive).

Real Power: The rate at which energy is delivered to a load to be transformed into heat, light, or physical motion.

Reliability: The ongoing ability of a power system to avoid outages and continue to supply electricity with the appropriate frequency and voltage to customers.

Reserve Margin: The difference between generating capacity and peak load, expressed as a percentage of peak load.

Retail Wheeling: Wheeling for delivery of power to a retail customer.

Security: The ability of the bulk power system to withstand sudden disturbances, such as the failure of a generator or transmission line.

Speed Governor: A device on a generating unit which adjusts the unit's power output to maintain the exact frequency.

Stability: The ability to maintain synchronous operation following disturbance.

Substations: A collection of power system equipment, such as voltage transformers, circuit breakers, and switches.

Supervisory Control and Data Acquisition: Telemetry and control equipment which monitors voltages and power flows and coordinates the transmission line and voltage control equipment.

Telemetry: Monitoring and communication equipment.

Transmission Access: The ability to use a transmission system.

Transmission System: An interconnected group of individual lines, which transport electricity over long distances.

Volt: A unit of electromotive force or the electrical pressure that can push a current through a circuit; can be positive or negative.

Voltage: A measure of the difference in volts between any two conductors or between a conductor and the ground, which is considered to be zero.

Watt: The unit of measure of electrical power or the rate of doing work.

Wheeling: The use of the transmission facilities of one system to transmit power produced by other entities.

Wholesale Wheeling: Wheeling for delivery to a utility system.

Appendix B
Contractor Reports

Background Paper (available from Superintendent of Documents, U.S. Government Printing Office):

- Biological Effects of Power-Frequency Electric and Magnetic Fields; Carnegie Mellon University.

Working Papers of Volume II (available from the National Technical Information Service):

- Transmission Line Certification and Siting Procedures and Energy Planning Processes; Public Utilities Commission of Ohio and the West Virginia Public Service Commission.
- Electric Utility Generation and Transmission Planning and Coordination: Summary of Utility Responses; Public Utility Commission of Ohio.
- Summary of Responses of the Regional Reliability Councils; Public Utility Commission of Ohio.
- *Planning and Coordination of Utility Bulk Power Supplies and Transmission Capacity: Interview Data*, Ohio Public Utilities Commission.
- Case Studies on Increasing Transmission Access; Casazza, Schultz & Associates, Inc.
- Case Studies of Transmission Bottlenecks; Casazza, Schultz & Associates, Inc.
- Technological Considerations in Proposed Scenarios; Power Technologies, Inc.
- Technical Background and Considerations in Proposed Wheeling, Transmission Access, and Non-utility Generation; Power Technologies, Inc.
- Competition and the Role of the Capital Markets in Restructuring the Electric Power Industry; Investor Responsibility Research Center.
- *The Siting of EHV Electric Transmission Lines*, James S. Cannon.
- Environmental Effects of Increased Competition in the Electric Power Industry; Kennedy P. Maize.
- Economic and Planning Implications of the FERC Notice Of Proposed Rulings on Independent Power Producers; The Energy Center, University of Pennsylvania.
- Survey of Power Industry Competition; OTA.
- Competitive Procurement of Generation Capacity: Summary of Procedures in Selected States; Boston Pacific Co., Inc.

Assessments in Progress as of May 1989

Technological Risks and Opportunities for Future U.S. Energy Supply and Demand
High-Temperature Superconductors: Research, Development, and Applications
Technology, Innovation, and U.S. Trade
Superfund Implementation
Training in the Workplace: Implications for U.S. Competitiveness
Advanced Space Transportation Technologies
Monitoring and Preventing Accidental Radiation Release at the Nevada Test Site
Agricultural Approaches To Reduce Agrichemical Contamination of Groundwater in the United States
U.S. Universities and Development Assistance: Technical Support for Agriculture, Natural Resources, and Environment
Emerging Agricultural Technology and the 1990 Farm Bill
Renewable Resources Planning Technologies for Public Lands
Monitoring of Mandated Vietnam Veteran Studies
Unconventional Cancer Treatments
Drug Labeling in Developing Countries—Phase II
Federal Response to AIDS: Congressional Issues
Preventive Health Services Under Medicare
Adolescent Health
Rural Health Care
Medicare's Prescription Drug Benefit: Alternative Payment Policies
Methods for Locating and Arranging Health and Long-Term Care Services for Persons With Dementia
New Developments in Neuroscience
Genetic Testing in the Workplace
Forensic Uses of Genetic Tests
Biotechnology in a Global Economy: Options for U.S. Strategy
Communications Systems for an Information Age
Copyright and Home Copying
Securities Markets and Information Technology
Information Technology and Research
New Clean Air Act Issues
Catching Our Breath: New Steps for Reducing Urban Ozone
Municipal Solid Waste Management
Managing Low-Level Radioactive Waste
Climate Change: Ozone Depletion and the Greenhouse Effect
Potential for Mineral Resources Development in Antarctica and the Convention of the Regulation of Antarctic Mineral Resource Activities
Infrastructure Technologies: Rebuilding the Foundations
Technologies for Learning at a Distance

NOTE: For brief descriptions of these studies in progress, see OTA's booklet on "Assessment Activities"—available from OTA's Publications Office, 224-8996.

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The Office of Technology Assessment (OTA) was created in 1972 as an analytical arm of Congress. OTA's basic function is to help legislative policymakers anticipate and plan for the consequences of technological changes and to examine the many ways, expected and unexpected, in which technology affects people's lives. The assessment of technology calls for exploration of the physical, biological, economic, social, and political impacts that can result from applications of scientific knowledge. OTA provides Congress with independent and timely information about the potential effects—both beneficial and harmful—of technological applications.

Requests for studies are made by chairmen of standing committees of the House of Representatives or Senate; by the Technology Assessment Board, the governing body of OTA; or by the Director of OTA in consultation with the Board.

The Technology Assessment Board is composed of six members of the House, six members of the Senate, and the OTA Director, who is a nonvoting member.

OTA has studies under way in nine program areas: energy and materials; industry, technology, and employment; international security and commerce; biological applications; food and renewable resources; health; communication and information technologies; oceans and environment; and science, education, and transportation.

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